CHAPTER 4

FUGITIVE EMISSIONS

Authors

Christian Boettcher (Germany), Amit Garg (India), Paul Nzomo Mbuthi (Kenya), Steven J. Oliver (Australia), Roberta Quadrelli (Italy), Cynthia Ann Randles (USA/Australia), Raquel Rodrigues de Souza (Brazil), Ajay Kumar Singh (India), Michael Strogies (Germany), Kostyantyn Tadlya (Ukraine), Nina Uvarova (Russia), John D. Watterson (UK), Melissa M. Weitz (USA), Francis Davison Yamba (Zambia), Shengmin Yu (China), and Songli Zhu (China)

Contributing Authors

Steven C. Smyth (Canada) and Jongikhaya Witi (South Africa)

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4 FUGITIVE EMISSIONS

Users are expected to go to Mapping Tables in Annex 2, before reading this chapter. This is required to correctly understand both the refinements made and how the elements in this chapter relate to the corresponding chapter in the 2006 IPCC Guidelines.

Intentional or unintentional release of greenhouse gases may occur during the extraction, processing, transformation and delivery of fossil fuels to the point of final use. These are known as fugitive emissions. Certain fugitive emissions from biomass are included here as well, such as fugitives of biogas from natural gas systems (e.g. distribution pipelines), and fugitives during fuel transformation for charcoal.

4.1 FUGITIVE EMISSIONS FROM MINING, PROCESSING, STORAGE AND TRANSPORTATION OF COAL

4.1.1 Overview and description of sources

Fugitive emissions associated with coal can be considered in terms of the following broad categories.[1]

4.1.1.1 COAL MINING, HANDLING AND EXPLORATION

The geological processes of coal formation also produce methane (CH_4), and carbon dioxide (CO_2) may also be present in some coal seams. These are known collectively as seam gas, and remain trapped in the coal seam until the coal is exposed and broken during mining. CH_4 is the major greenhouse gas emitted from coal mining and handling.

The major stages for the emission of greenhouse gases for both underground and surface coal mines are:

- **Mining emissions** – These emissions result from the liberation of stored gas during the breakage of coal, and the surrounding strata, during mining operations.
- **Post-mining emissions** – Not all gas is released from coal during the process of coal breakage during mining. Emissions, during subsequent handling, processing and transportation of coal are termed post-mining emissions. Therefore coal normally continues to emit gas *even after it has been mined*, although more slowly than during the coal breakage stage.
- **Low temperature oxidation** - These emissions arise because once coal is exposed to oxygen in air, the coal oxidizes to produce CO_2. However, the rate of formation of CO_2 by this process is low.
- **Uncontrolled combustion** – On occasions, when the heat produced by low temperature oxidation is trapped, the temperature rises and an active fire may result. This is commonly known as uncontrolled combustion and is the most extreme manifestation of oxidation. Uncontrolled combustion is characterised by rapid reactions, sometimes visible flames and rapid CO_2 formation, and may be natural or anthropogenic. It is noted that uncontrolled combustion only due to coal exploitation activities is considered here.
- **Exploration emissions –** These emissions result from boreholes drilled through carbonaceous strata for the purposes of coal exploration. This is distinct from gas drainage boreholes which form part of a degasification system, which are included for under Mining Emissions.

After mining has ceased, **abandoned coal mines** may also continue to emit methane.

A brief description of some of the major processes that need to be accounted for in estimating emissions for the different types of coal mines follows:

UNDERGROUND MINES

Active Underground Coal Mines

The following *potential* source categories for fugitive emissions for active underground coal mines are considered in this document:

[1] Methods for determining emissions from *peat extraction* are described in Volume 4 AFOLU Chapter 7 'Wetlands'.

- Seam gas emissions vented to the atmosphere from coal mine *ventilation air* and *degasification systems*
- Post-mining emissions
- Low temperature oxidation
- Uncontrolled combustion

Coal mine ventilation air and degasification systems arise as follows:

Coal Mine Ventilation Air

Underground coal mines are normally ventilated by flushing air from the surface, through the underground tunnels in order to maintain a safe atmosphere. Ventilation air picks up the CH_4 and CO_2 released from the coal formations and transports these to the surface where they are emitted to atmosphere. The concentration of CH_4 in the ventilation air is normally low, but the volume flow rate of ventilation air is normally large and therefore the methane emissions from this source can be very significant.

Coal Mine Degasification Systems

Degasification systems comprise wells drilled before, during, and after mining to drain gas (mainly CH_4) from the coal seams that release gas into the mine workings. During active mining the major purpose of degasification is to maintain a safe working atmosphere for the coal miners, although the recovered gas may also be utilised as an energy source. Degasification systems can also be used at abandoned underground coal mines to recover methane. The amount of methane recovered from coal mine degasification systems can be very significant and is accounted for, depending on its final use, as described in Section 4.1.3.2 of this chapter.

Abandoned Underground Mines

After closure, coal mines that were significant CH_4 emitters during mining operations continue to emit methane unless there is flooding that cuts off the emissions. Even if the mines have been sealed, methane may still be emitted to the atmosphere as a result of gas migrating through natural or manmade conduits such as old portals, vent pipes, or cracks and fissures in the overlying strata. Emissions quickly decline until they reach a near-steady rate that may persist for an extended period of time.

Abandoned mines may flood as a result of intrusion of groundwater or surface water into the mine void. These mines typically continue to emit gas for a few years before the mine becomes completely flooded and the water prevents further methane release to the atmosphere. Emissions from completely flooded abandoned mines can be treated as negligible. Mines that remain partially flooded can continue to produce methane emissions over a long period of time, as with mines that do not flood.

A further potential source of emissions occurs when some of the coal from abandoned mines ignites through the mechanism of uncontrolled combustion. However, there are currently no methodologies for estimating potential emissions from uncontrolled combustion at abandoned underground mines.

SURFACE COAL MINES

Active Surface Mines

The *potential* source categories for surface mining considered in this chapter are:

- Methane and CO_2 emitted during mining from breakage of coal and associated strata and leakage from the pit floor and highwall
- Post-mining emissions
- Low temperature oxidation
- Uncontrolled combustion in waste dumps

Emissions from surface coal mining occur because the mined and surrounding seams may also contain CH_4 and CO_2. Although the gas contents are generally less than for deeper underground coal seams, the emission of seam gas from surface mines needs to be taken into account, particularly for countries where this mining method is widely practised. In addition to seam gas emissions, the waste coal that is dumped into overburden or reject dumps may generate CO_2, either by low temperature oxidation or by uncontrolled combustion.

Abandoned Surface Mines

After closure, abandoned or decommissioned surface mines may continue to emit methane as the gas leaks from the coal seams that were broken or damaged during mining. There are at present no methods for estimating emissions from this source.

COAL EXPLORATION

This source category includes emissions arising from boreholes drilled for coal mining exploration purposes. It does not include coal gas drainage wells used to collect gas prior to, or as a part of coal mining activities. Fugitive emissions from coal seam gas drainage wells are included in Underground and Surface Mining Activities. Gas drainage or production boreholes that consist of a coal seam gas exploration aspect exclusively, are not to be counted as coal exploration boreholes, and are instead included under 1.B.2.

The overall coal exploration process involves drilling of vertical boreholes from the surface of the Earth to detect the presence of coal seams, their depth of occurrence, thickness and other geological structures, resource and chemical characteristics such as ash, moisture, volatile matter (VM) and fixed carbon (FC). A small fraction of the methane gas retained by the coal seams may be released during borehole drilling and escape to the atmosphere. Emissions will occur only if the borehole drilling penetrates some gas bearing strata such as coal and carbonaceous shale.

Boreholes and wells associated with coal gas drainage and coal bed methane/natural gas exploration are focused on determining gas flow, and gas bearing strata are often stimulated to increase gas flow. Coal exploration boreholes are focused on obtaining core samples or understanding strata geophysics, and therefore the coal fracture systems are not artificially stimulated. Thus, the gas flow from coal exploration boreholes and coal bed methane/natural gas boreholes are not comparable.

4.1.1.2 SUMMARY OF SOURCES

The major sources are summarised in Table 4.1.1 below.

TABLE 4.1.1 (UPDATED)
DETAILED SECTOR SPLIT FOR EMISSIONS FROM MINING, PROCESSING, STORAGE AND TRANSPORT OF COAL

IPCC code	Category/subcategory	
1 B	*Fugitive emissions from fuels*	Includes all intentional and unintentional emissions from the extraction, processing, storage and transport of fuel to the point of final use.
1 B 1	*Solid Fuels*	Includes all intentional and unintentional emissions from the extraction, processing, storage and transport of solid fuel to the point of final use.
1 B 1 a	*Coal mining and handling*	Includes all fugitive emissions from coal
1 B 1 a i	*Underground mines*	Includes all emissions arising from mining, post-mining, abandoned mines and flaring of drained methane.
1 B 1 a i 1	*Mining*	Includes all seam gas emissions vented to atmosphere from coal mine ventilation air and degasification systems.
1 B 1 a i 2	*Post-mining seam gas emissions*	Includes methane and CO_2 emitted after coal has been mined, brought to the surface and subsequently processed, stored and transported.
1 B 1 a i 3	*Abandoned underground mines*	Includes methane emissions from abandoned underground mines
1 B 1 a i 4	*Flaring of drained methane or conversion of methane to CO_2*	Methane drained and flared, or ventilation gas converted to CO_2 by an oxidation process should be included here. Methane used for energy production should be included in Volume 2, Energy, Chapter 2 'Stationary Combustion'.
1 B 1 a ii	*Surface mines*	Includes all seam gas emissions arising from surface coal mining
1 B 1 a ii 1	*Mining*	Includes methane and CO_2 emitted during mining from breakage of coal and associated strata and leakage from the pit floor and highwall

TABLE 4.1.1 (UPDATED) (CONTINUED) DETAILED SECTOR SPLIT FOR EMISSIONS FROM MINING, PROCESSING, STORAGE AND TRANSPORT OF COAL		
IPCC code	**Category/subcategory**	
1 B 1 a ii 2	*Post-mining seam gas emissions*	Includes methane and CO_2 emitted after coal has been mined, subsequently processed, stored and transported.
1 B 1 a ii 3	*Abandoned surface mines*	Includes methane emissions from abandoned surface mines.
1 B 1 a iii	*Coal exploration*	Includes methane emissions from boreholes drilled for the purposes of coal exploration.
1 B 1 b	*Uncontrolled combustion and burning coal dumps*	Includes emissions of CO_2 from uncontrolled combustion due to coal exploitation activities.

4.1.2 Methodological issues

The following sections focus on methane emissions, as this gas is the most important fugitive emission for coal mining. Methods for estimating carbon dioxide emissions from underground and surface mining are also provided. Carbon dioxide emissions from other coal mining sources such as post-mining and abandoned mines should also be included in the inventory where data are available.

UNDERGROUND MINING

Fugitive emissions from underground mining arise from both ventilation and degasification systems. These emissions are normally emitted at a small number of centralised locations and can be considered as point sources. They are amenable to standard measurement methods.

SURFACE MINING

For surface mining the emissions of greenhouse gases are generally dispersed over sections of the mine and are best considered area sources. These emissions may be the result of seam gases emitted through the processes of breakage of the coal and overburden, low temperature oxidation of waste coal or low quality coal in dumps, and uncontrolled combustion. Measurement methods for low temperature oxidation and uncontrolled combustion are still being developed and therefore estimation methods are not included in this chapter.

ABANDONED MINES

Abandoned underground mines present difficulties in estimating emissions, although a methodology for abandoned underground mines is included in this chapter. Methodologies do not yet exist for abandoned or decommissioned surface mines, and therefore they are not included in this chapter.

EXPLORATION

A large fraction of the gas contained in coal seams is adsorbed on the coal surface inside the micropores and a small fraction in the free state in the macro pores and cleats. The hydrostatic pressure that a coal seam is subjected to prevents desorption of the gas from the coal matrix. Gas flow from exploration boreholes is not comparable to the flow of gas in coalbed methane wells where the coal seams are stimulated by hydro fracturing and depressurized by dewatering the coal seams. Emissions during exploratory borehole drilling may be largely associated with the amount of coal or lignite added to the national resource (found as a result of exploration) during the reporting period. This addition of resource is termed as augmentation of resource during the period.

METHANE RECOVERY AND UTILISATION

Methane recovered from drainage, ventilation air, or abandoned mines may be mitigated in two ways: (1) direct utilization as a natural gas resource or (2) by flaring to produce CO_2, which has a lower greenhouse warming potential than methane.

TIERS

Use of appropriate tiers to develop emissions estimates for coal mining in accordance with *good practice* depends on the quality of data available. For instance, if limited data are available and the category is not key, then Tier 1 is *good practice*. The Tier 1 approach requires that countries choose from a global average range of emission factors and use country-specific activity data to calculate total emissions. Tier 1 is associated with the highest level of uncertainty. The Tier 2 approach uses country- or basin-specific emission factors that represent the average values for the coals being mined. These values are normally developed by each country, where appropriate. The Tier 3 approach uses direct measurements on a mine-specific basis and, properly applied, has the lowest level of uncertainty.

4.1.3 Underground coal mines

The general form of the equation for estimating emissions for Tier 1 and 2 approaches, based on coal production activity data *from underground coal mining and post-mining emissions* is given by Equation 4.1.1 below. Methods to estimate emissions from *abandoned* underground mines are described in detail in Section 4.1.5.

Equation 4.1.1 represents emissions before adjustment for any utilisation or flaring of recovered gas:

EQUATION 4.1.1
ESTIMATING EMISSIONS FROM UNDERGROUND COAL MINES FOR TIER 1 AND TIER 2 WITHOUT ADJUSTMENT FOR METHANE UTILISATION OR FLARING

Greenhouse gas emissions = Raw coal production● Emission Factor● Units conversion factor

The definition of the Emission Factor used in this equation depends on the activity data used. For Tier 1 and Tier 2, the Emission Factor for underground, surface and post-mining emissions has units of m^3 $tonne^{-1}$, the same units as in situ gas content. This is because these Emission Factors are used with activity data on raw coal production which has mass units (i.e. tonnes). However, the Emission Factor and th*e in situ* gas content are not the same and should not be confused. The Emission Factor is always larger than the *in situ* gas content, because the gas released during mining draws from a larger volume of coal and adjacent gas-bearing strata than simply the volume of coal produced. For abandoned underground mines, the Emission Factor has different units, because of the different methodologies employed, see Section 4.1.5 for greater detail.

The equation to be used along with Equation 4.1.1 in order to adjust for methane utilisation and flaring for Tier 1 and Tier 2 approaches is shown in Equation 4.1.2.

EQUATION 4.1.2 (UPDATED)
ESTIMATING EMISSIONS FROM UNDERGROUND COAL MINES FOR TIER 1 AND TIER 2 WITH ADJUSTMENT FOR METHANE UTILISATION OR FLARING

CH_4 emissions from underground mining activities = Emissions from underground mining CH_4 + Post-mining emission of CH_4 – CH_4 recovered and utilized for energy production or flared

CO_2 emissions from underground mining activities = Emissions from underground mining CO_2 - the amount of CO_2 contained in the gas recovered for energy production + Emissions of CO_2 from methane flared or catalytically oxidised

Emissions of CH_4 from underground mines in Equations 4.1.1 and 4.1.2 include abandoned mines (see Section 4.1.5) and both go into the total for 1.B.1.a.i (Underground mines). Theoretically, Equations 4.1.1 and 4.1.2 should also include CO_2 emissions from post-mining activities and abandoned mines. However, considering that Section 4.1.3.2 and 4.1.5 below provides no methods or emission factors for neither of those two CO_2 emission sources, therefore the general equations for CO_2 here are simply the emissions from underground mining operations.

Equation 4.1.2 is used for Tiers 1 and 2 because they use Emission Factors to account for emissions from coal mines on a national or coal-basin level. The emission factors already include all the methane likely to be released from mining activities. Thus, any methane recovery and utilization must be explicitly accounted for by the subtraction term in Equation 4.1.2.

Similarly, where gas from coal seams is recovered for fuel combustion, the amount of CO_2 contained in the recovered gas should also be accounted for by the subtraction term in Equation 4.1.2. That CO_2 will be eventually be accounted for in the categories where the gas from coal seam are consumed under Chapter 2 Stationary Combustion.

If the gas recovered from coal seams is flared or catalytically oxidised with no useful energy, then the amount of CO_2 contained in that recovered gas is accounted as fugitive emissions under 1 B 1 a i 4, using Equation 4.1.5.

Tier 3 methods involve mine-specific calculations which take into account the methane drained and recovered from individual mines rather than emission factors, and therefore Equation 4.1.2 is not appropriate for Tier 3 methods.

4.1.3.1 CHOICE OF METHOD

UNDERGROUND MINING

Figures 4.1.1 and 4.1.1a shows the methane and carbon dioxide decision trees for underground coal mining activities. For countries with underground mining, and where mine-specific measurement data are available it is *good practice* to use a Tier 3 method. Mine-specific CH_4 and CO_2 data, based on ventilation air measurements and degasification system measurements, reflect actual emissions on a mine-by-mine basis, and therefore produce a more accurate estimate than using Emission Factors.

Hybrid Tier 3 - Tier 2 approaches are appropriate in situations when mine-specific measurement data are available only for a subset of underground mines. For example, if only mines that are considered gassy report data, emissions from the remaining mines can be calculated with Tier 2 emission factors. The definition of what constitutes a gassy mine will be determined by each country. For instance, in the United States, gassy mines refers to coal mines with average annual ventilation emissions exceeding the range of 2 800 to 14 000 cubic meters per day. Emission factors can be based on specific emission rates derived from Tier 3 data if the mines are operating within the same basin as the Tier 3 mines, or on the basis of mine-specific properties, such as the average depth of the coal mines.

When no mine-by-mine data are available, but country- or basin-specific data are, it *is good practice* to employ the Tier 2 method.

Where no data (or very limited data) are available, it is *good practice* to use a Tier 1 approach, provided underground coal mining is not a key sub source category. If it is, then it is *good practice* to obtain emissions data to increase the accuracy of these emissions estimates (see Figures 4.1.1 and 4.1.1a). A reliable relationship between CH_4 and CO_2 emissions levels from underground coal mining is not able to be established as of now for the purposes of emission estimation. Therefore emission methods based on correlation between CH_4 and CO_2 are not provided.

POST-MINING

Direct measurement (Tier 3) of all post-mining emissions is not feasible, so an emission factor approach must be used. The Tier 2 and Tier 1 methods described below represent *good practice* for this source, given the difficulty of obtaining better data.

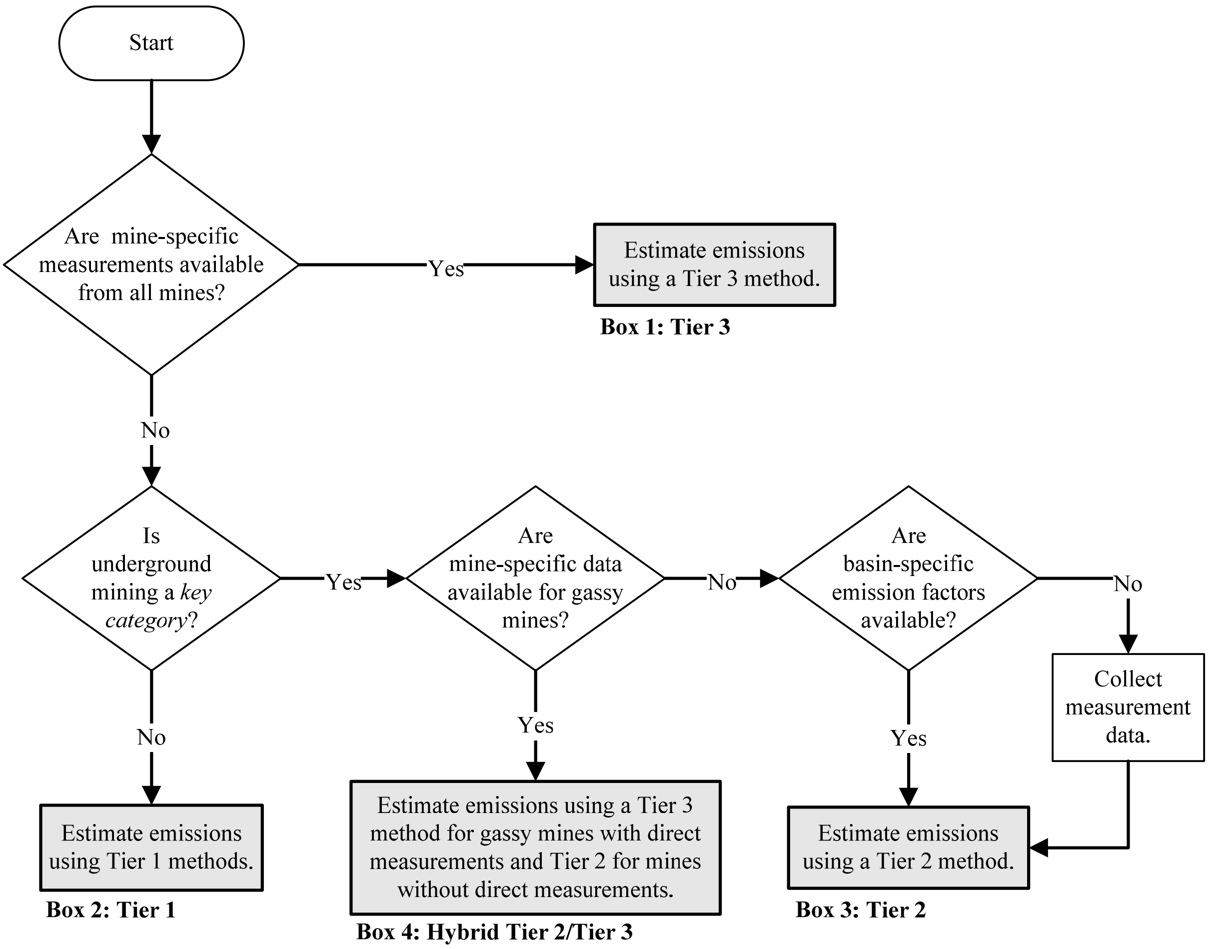
LOW TEMPERATURE OXIDATION

Oxidation of coal when it is exposed to the atmosphere by coal mining releases CO_2. Coal low temperature oxidation is one among other sources of CO_2 during mining activity. Tier 1 approach uses emission factors that cover all fugitive sources of CO_2 including low temperature oxidation.

ABANDONED UNDERGROUND MINES

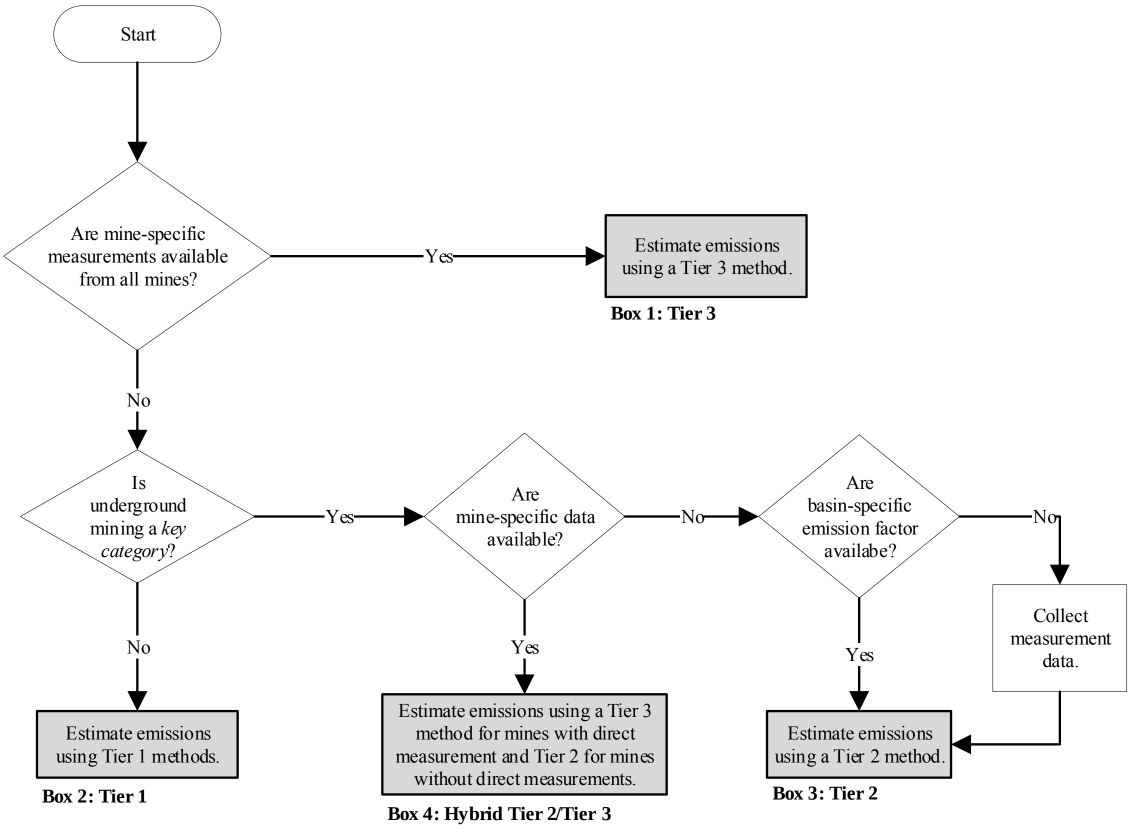
Fugitive methane emissions from abandoned underground mines should be reported in Underground Mines in IPCC Category 1.B.1.a.i.3, using the methodology presented in Section 4.1.5.

Figure 4.1.1 (Updated) Decision tree for methane from underground coal mines



Note: See Volume 1 Chapter 4, "Methodological Choice and *Key Categories*" (noting Section 4.1.2 on limited resources) for discussion of *key categories* and use of decision trees

Figure 4.1.1a (New) Decision tree for carbon dioxide from underground coal mines



Note: See Volume 1 Chapter 4, "Methodological Choice and *Key Categories*" (noting Section 4.1.2 on limited resources) for discussion of *key categories* and use of decision trees

4.1.3.2 CHOICE OF EMISSION FACTORS FOR UNDERGROUND MINES

MINING

Methane

Tier 1 Emission Factors for underground mining are shown below. The emission factors are the same as those described in the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (BCTSRE, 1992; Bibler et al, 1991; Lama, 1992; Pilcher et al, 1991; USEPA, 1993a,b and Zimmermeyer, 1989).

EQUATION 4.1.3 (UPDATED)
TIER 1: GLOBAL AVERAGE METHOD – UNDERGROUND MINING – METHANE – BEFORE ADJUSTMENT FOR ANY METHANE UTILISATION OR FLARING

$$CH_4\ emissions = CH_4\ Emission\ Factor \bullet Underground\ Coal\ Production \bullet Conversion\ Factor$$

Where units are:

Methane Emissions (Gg year^{-1})

CH_4 Emission Factor (m^3 tonne^{-1})

Underground Coal Production (tonne year^{-1})

Emission Factor:

Low CH_4 Emission Factor = 10 m^3 tonne^{-1}

Average CH_4 Emission Factor =18 m^3 tonne^{-1}

High CH_4 Emission Factor = 25 m^3 tonne^{-1}

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 0.67 ● 10^{-6} Gg $m^{-3.}$

Countries using the Tier 1 approach should consider country-specific variables such as the depth of major coal seams to determine the emission factor to be used. As gas content of coal usually increases with depth, the low end of the range should be chosen for average mining depths of <200 m, and for depths of > 400 m the high value is appropriate. For intermediate depths, average values can be used.

For countries using a Tier 2 approach, basin-specific emission factors may be obtained from sample ventilation air data or from a quantitative relationship that accounts for the gas content of the coal seam and the surrounding strata affected by the mining process, along with raw coal production. For a typical longwall operation, the amount of gas released comes from the coal being extracted and from any other gas-bearing strata that are located within 150 m above and 50 m below the mined seam (*Good Practice Guidance*, 2000).

Carbon dioxide

Tier 1 Emission Factors for underground mining are shown below. The emission factors have been derived from National Inventory Reports, scientific literature and data reported to national reporting programs of the following countries: Australia, China, Czech Republic, India, Japan, Slovakia, Slovenia, South Africa, Russia and Ukraine. The average emission factor is taken from the mean of the latest implied emission factors from each of these countries.

(Moscow Geological Prospecting Institute 1979; Moscow Geological Prospecting Institute 1980; China State Administration of Coal Mine Safety 2012; Central Institute of Mining and Fuel Research 2016; Commonwealth of Australia 2017; Czech Hydrometeorological Institute 2017; Ministry of the Environment and Spatial Planning of the Republic of Slovenia 2017; Slovak Hydrometeorological Institute 2017; Geological Survey of India 2017; Ministry of the Environment Japan 2017; Yu et al. 2018)

EQUATION 4.1.3A (NEW)
TIER 1: GLOBAL AVERAGE METHOD – UNDERGROUND MINING – CARBON DIOXIDE

CO_2 emissions = CO_2 Emission Factor ● Underground Coal Production ● Conversion Factor

Where units are:

Carbon dioxide Emissions (Gg $year^{-1}$)

CO_2 Emission Factor (m^3 $tonne^{-1}$)

Underground Coal Production (tonne $year^{-1}$)

Emission Factor:

Low CO_2 Emission Factor = 0.05 m^3 $tonne^{-1}$

Average CO_2 Emission Factor = 5.9 m^3 $tonne^{-1}$

High CO_2 Emission Factor = 12.3 m^3 $tonne^{-1}$

Conversion Factor:

This is the density of CO_2 and converts volume of CO_2 to mass of CO_2. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 1.84 ● 10^{-6} Gg m^{-3} (GOST 2015).

Countries should use the Average CO_2 Emission Factor unless there is country-specific evidence to support use of an alternative factor within the low/high range. Countries may consider country-specific circumstances such as geological location/basis/depth to determine the emission factor to be used. Where CO_2 outbursts have been frequently observed as a safety concern in mining, then a country should consider the use of the high end CO_2 emission factor.

For countries using a Tier 2 approach, basin-specific emission factors may be obtained from analysis of ventilation air data. When assessing CO_2 gas volumes in mine ventilation systems, care needs to be taken to exclude CO_2 from non-fugitive sources such as;

- ambient carbon dioxide present in the air that was drawn into the mine ventilation intake - to take into account the atmospheric CO_2 constant of the air drawn into the intake of the ventilation system.
- fuel combustion CO_2 emissions arising from the use of machinery, while the machinery is in the underground mine.

A Tier 3 approach, is based on direct measurement of gas composition. For countries using a Tier 3 approach an assessment of CO_2 gas volumes in mine ventilation systems needs to be taken to exclude CO_2 of above mentioned non-fugitive sources. Basin-specific emission factors may be obtained from analysis of ventilation air data.

POST-MINING EMISSIONS

For a Tier 1 approach the post-mining emissions factors are shown below together with the estimation method:

EQUATION 4.1.4

TIER 1: GLOBAL AVERAGE METHOD – POST-MINING EMISSIONS – UNDERGROUND MINES

Methane emissions = CH_4 Emission Factor ● Underground Coal Production ● Conversion Factor

Where units are:

Methane Emissions (Gg $year^{-1}$)

CH_4 Emission Factor (m^3 $tonne^{-1}$)

Underground Coal Production (tonne $year^{-1}$)

Emission Factor:

Low CH_4 Emission Factor = 0.9 m^3 $tonne^{-1}$

Average CH_4 Emission Factor = 2.5 m^3 $tonne^{-1}$

High CH_4 Emission Factor = 4.0 m^3 $tonne^{-1}$

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6}$ Gg m^{-3}.

Tier 2 methods to estimate post-mining emissions take into account the *in situ* gas content of the coal. Measurements on coal as it emerges on a conveyor from an underground mine without degasification prior to mining indicate that 25-40 percent of the *in situ* gas remains in the coal (Williams and Saghafi, 1993). For mines that practice pre-drainage, the amount of gas in coal will be less than the *in situ* value by some unknown amount. For mines with no pre-drainage, but with knowledge of the *in situ* gas content, the post-mining emission factor can be set at 30 percent of the *in situ* gas content. For mines with pre-drainage, an emission factor of 10 percent of the *in situ* gas content is suggested.

Tier 3 methods are not regarded as feasible for post-mining operations.

EMISSIONS FROM DRAINED METHANE

Methane drained from working (or abandoned) underground (or surface) coal mines can be vented directly to the atmosphere, recovered and utilised, or converted to CO_2 through combustion (flaring or catalytic oxidation) without any utilisation. The manner of accounting for drained methane varies, depending on the final use of the methane.

In general:

- Tier 1 represents an aggregate emissions estimate using emission factors. In general, it is not expected that emissions associated with drained methane would be applicable for Tier 1. Presumably, if methane were being drained, there would be better data to enable use of Tier 2 or even Tier 3 methods to make emissions estimates. However, Tier 1 has been included in the discussion below, in case Tier 1 methods are being used to estimate national emissions where there are methane drainage operations.
- When methane is drained from coal seams as part of coal mining and subsequently flared or used as a fuel, it is *good practice* to subtract this amount from the total estimate of methane emissions for Tier 1 and Tier 2 (Equation 4.1.2). Data on the amount of methane that is flared or otherwise utilised should be obtained from mine operators with the same frequency of measurement as pertains to underground mine emissions generally.
- For Tiers 1 and 2, if methane is drained and vented to the atmosphere rather than utilized, it should not be re-counted as it already forms part of the emissions estimates for these approaches.
- For Tier 3, methane recovered from degasification systems and vented to the atmosphere prior to mining should be added to the amount of methane released through ventilation systems so that the total estimate is complete. In some cases, because degasification system data are considered confidential, it may be necessary to estimate degasification system collection efficiency, and then subtract known reductions to arrive at the net degasification system emissions.

- All methane emissions associated with coal seam degasification related to coal mining activities should be accounted for in the inventory year in which the emissions and recovery operations occur. Thus, the total emissions from all ventilation shafts and from all degasification operations that emit methane to the atmosphere are reported for each year, regardless of when the coal seam is mined through, as long as the emissions are associated with mining activities.
- When coal bed methane is extracted from coal seams and is delivered into a natural gas system, then the fugitive emissions associated with the exploration, production, processing, transmission and storage are dealt with in the oil and natural gas source category (Section 4.2). Tier 1 fugitive emission factors for coal bed methane production are provided under 1B 2 b iii 2 Production and Gathering in Table 4.2.10.

When recovered methane is utilized as an energy source:

- Any emissions resulting from use of recovered coal mine methane as an energy source should be accounted for based on its final end-use, for example in the Energy Volume, Chapter 2, 'Stationary Combustion' when used for stationary energy production.
- Where recovered methane from coal seams is fed into a natural gas system and used as natural gas, the *fugitive* emissions occurring as part of those natural gas systems are dealt with in the oil and natural gas source category (Section 4.2).

When recovered methane is flared:

- When the methane is simply combusted with no useful energy, as in flaring or catalytic oxidation to CO_2, the corresponding CO_2 production should be added to the total greenhouse gas emissions (expressed as CO_2 equivalents) from coal mining activities. Such emissions should be accounted for as shown by Equation 4.1.5, below. Amounts of nitrous oxide and non-methane volatile organic compounds emitted during flaring will be small relative to the overall fugitive emissions and need not be estimated.

EQUATION 4.1.5
EMISSIONS OF CO_2 AND CH_4 FROM DRAINED METHANE FLARED OR CATALYTICALLY OXIDISED

$$(a)\ \text{Emissions of } CO_2 \text{ from } CH_4 \text{ combustion} = 0.98 \bullet \text{Volume of methane flared} \bullet \text{Conversion Factor} \bullet \text{Stoichiometric Mass Factor}$$

$$(b)\ \text{Emissions of unburnt methane} = 0.02 \bullet \text{Volume of methane flared} \bullet \text{Conversion Factor}$$

Where units are:

Emissions of CO_2 from methane combustion (Gg year^{-1})

Volume of methane flared (m^3 year^{-1})

Stoichiometric Mass Factor is the mass ratio of CO_2 produced from full combustion of unit mass of methane and is equal to 2.75

Note: 0.98 represents the combustion efficiency of natural gas that is flared (Compendium of Greenhouse Gas Emission Methodologies for the Oil and gas Industry, American Petroleum Institute, 2004)

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6}$ Gg m^{-3}.

4.1.3.3 CHOICE OF ACTIVITY DATA

No refinement

4.1.3.4 COMPLETENESS FOR UNDERGROUND COAL MINES

No refinement.

4.1.3.5 DEVELOPING A CONSISTENT TIME SERIES

No refinement.

4.1.3.6 UNCERTAINTY ASSESSMENT

EMISSION FACTOR UNCERTAINTIES

Emission Factors for Tiers 1 and 2

The major sources of uncertainty for a Tier 1 approach arise from two sources. These are:

- The applicability of global emission factors to individual countries
- Inherent uncertainties in the emission factors themselves

The uncertainty due to the first point above is difficult to quantify, but could be significant. The inherent uncertainty in the emission factor is also difficult to quantify because of natural variability within the same coal region is known to occur.

For a Tier 2 approach, the same broad comments apply, although basin-specific data will reduce the inherent uncertainty in the Emission Factor compared with a Tier 1 approach. With regard to the inherent variability in the Emission Factor, 'Expert Judgement' in the *Good Practice Guidance (2000*) suggested that this was likely to be at least ±50 percent.

Table 4.1.2 shows the Tier 1 and Tier 2 uncertainties associated with emissions from underground coal mining. The uncertainties for these Tiers are based on expert judgement.

TABLE 4.1.2 (UPDATED)
ESTIMATES OF UNCERTAINTY FOR UNDERGROUND MINING FOR TIER 1 AND TIER 2 APPROACHES

Likely uncertainties of coal mine methane Emission factors (Expert judgment - GPG, 2000*)		
Method	**Mining**	**Post-Mining**
Tier 2	± 50-75%	± 50%
Tier 1	Factor of 2 greater or smaller	Factor of 3 greater or smaller
*GPG, 2000 *IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (2000)		
Likely uncertainties of coal mine carbon dioxide emission factors *		
Method	**Mining**	**Post-Mining**
Tier 2	± 50-75%	Not applicable
Tier 1	-50% to +100%	Not applicable
*Uncertainties set to be consistent with methane emission factors given that measurement practices are likely to be similar		

Tier 3

Methane emissions from underground mines have a significant natural variability due to variations in the rate of mining and drainage of gas. For instance, the gas liberated by longwall mining can vary by a factor of up to two during the life of a longwall panel. Frequent measurements of underground mine emissions can account for such variability and also reduce the intrinsic errors in the measurement techniques. As emissions vary over the course of a year due to variations in coal production rate and associated drainage, *good practice* is to collect measurement data as frequently as practical, preferably biweekly or monthly to smooth out variations. Daily measurements would ensure a higher quality estimate. Continuous monitoring of emissions represents the highest stage of emission monitoring, and is implemented in some modern longwall mines.

Spot measurements of methane concentration in ventilation air are probably accurate to ±20 percent depending on the equipment used. Time series data or repeat measurements will significantly reduce the uncertainty of annual emissions to ±5 percent for continuous monitoring, and 10-15 percent for monitoring conducted every two weeks. Ventilation airflows are usually fairly accurately known (±2 percent). When combining the inaccuracies in emissions concentration measurements with the imprecision due to measurement and calculation of instantaneous measurements, overall emissions for an individual mine may be under-represented by as much as 10 percent or over-represented by as much as 30 percent (Mutmansky and Wang, 2000).

Spot measurement of methane concentration in drained gas (from degasification systems) is likely to be accurate to ±2 percent because of its higher concentration. Measurements should be made with a frequency comparable to those for ventilation air to obtain representative sampling. Measured degasification flow rates are probably known to be ±5 percent. Degasification flow rates that are estimated based on gas sales are also likely to have an uncertainty of at least ±5 percent due to the tolerances in pipeline gas quality.

For a single longwall operation, with continuous or daily emission measurements, the accuracy of monthly or annual average emissions data is probably ±5 percent. The accuracy of spot measurements performed every two weeks is ±10 percent, at 3-monthly intervals: ±30 percent. Aggregating emissions from mines based on the less frequent type of measurement procedures will reduce the uncertainty caused by fluctuations in gas production. However, as fugitive emissions are often dominated by contributions from only a small number of mines, it is difficult to estimate the extent of this improvement.

The uncertainty estimates for underground mines are shown in Table 4.1.3.

TABLE 4.1.3
ESTIMATES OF UNCERTAINTY FOR UNDERGROUND COAL MINING FOR A TIER 3 APPROACH

Source	Details	Uncertainty	Reference
Drainage gas	Spot measurements of CH_4 for drainage gas	± 2%	Expert judgment (GPG, 2000*)
	Degasification flows	± 5%	Expert judgment (GPG, 2000)
Ventilation gas	Continuous or daily measurements	± 5%	Expert judgment (GPG, 2000)
	Spot measurements every 2 weeks	± 10%	Mutmansky and Wang, 2000
	Spot measurements every 3 months	± 30%	Mutmansky and Wang, 2000

*GPG, 2000 - IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000)

ACTIVITY DATA UNCERTAINTIES

Coal production: Country-specific tonnages are likely to be known to 1-2 percent, but if raw coal data are not available, then the uncertainty will increase to about ±5 percent, when converting from saleable coal production data. The data are also influenced by moisture content, which is usually present at levels between 5-10 percent, and may not be determined with great accuracy.

Apart from measurement uncertainty, there can be further uncertainties introduced by the nature of the statistical databases that are not considered here. In countries with a mix of regulated and unregulated mines, activity data may have an uncertainty of ±10 percent

4.1.4 Surface coal mining

The fundamental equation to be used in estimating emissions from surface mining is as shown in Equation 4.1.6.

EQUATION 4.1.6 (UPDATED)
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM SURFACE COAL MINING

$$CH_4 \text{ emissions} = \text{Surface mining emissions of } CH_4 + \text{Post-mining emission of } CH_4$$

$$CO_2 \text{ emissions} = \text{Surface mining emissions of } CO_2 + \text{Post-mining emission of } CO_2$$

4.1.4.1 CHOICE OF METHOD

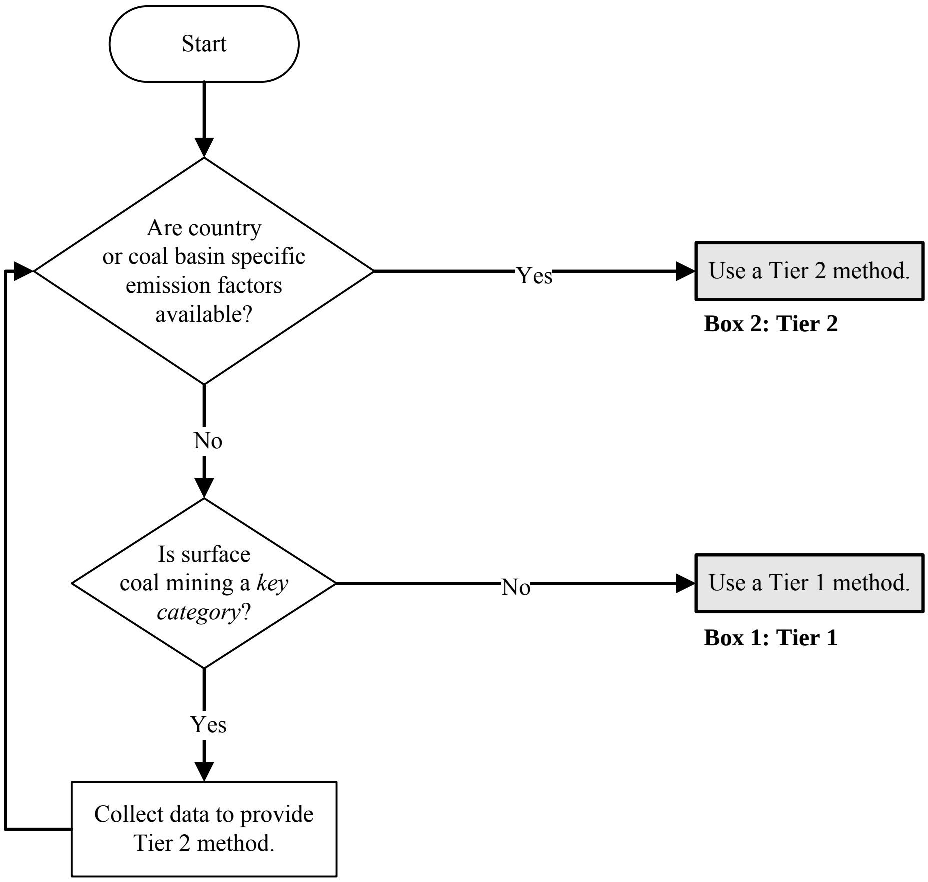
It is not yet feasible to collect mine-specific Tier 3 measurement data for surface mines. The alternative is to collect data on surface mine coal production and use emission factors. For countries with significant coal production and multiple coal basins, disaggregation of data and emission factors to the coal basin level will improve accuracy. Given the uncertainty of production-based emission factors, choosing emission factors from the range specified within these guidelines can provide reasonable estimates for a Tier 1 approach.

As with underground mining, direct measurement of post-mining emissions is infeasible so an emission factor approach is recommended. Tier 2 and Tier 1 methods should be reasonable for this source, given the difficulty of obtaining better data. A reliable relationship between CH_4 and CO_2 emissions levels from surface coal mining is not able to be established for the purposes of emission estimation. Therefore emission methods based on correlation between CH_4 and CO_2 are not provided.

Oxidation of coal in the atmosphere to produce CO_2 is known to occur at surface mines, but emissions from this are not expected to be significant, especially taking into account the effects of rehabilitation of the waste dumps. Rehabilitation practices, which involve covering the dumps with topsoil and re-vegetation, act to reduce oxygen fluxes into the dump and hence reduce the rate of CO_2 production. While no default method is provided for estimating Post-mining emissions of CO_2, countries may choose to provide their own country-specific emission estimate.

Uncontrolled combustion in waste piles is a feature for some surface mines. However, these emissions, where they occur, are extremely difficult to quantify and it is infeasible to include a methodology.

Figure 4.1.2 Decision tree for surface coal mining



Note: See Volume 1 Chapter 4, "Methodological Choice and *Key Categories*" (noting Section 4.1.2 on limited resources) for discussion of *key categories* and use of decision trees

4.1.4.2 EMISSION FACTORS FOR SURFACE MINING

Although measurements of methane and carbon dioxide emissions from surface mining are increasingly available, they are difficult to make and at present no routine widely applicable methods exist. Data on *in situ* gas contents before overburden removal are also scarce for many surface mining operations.

The Tier 1 methane emission factors are shown together with the estimation method in Equation 4.1.7.

EQUATION 4.1.7 (UPDATED)
TIER 1: GLOBAL AVERAGE METHOD – SURFACE MINES – METHANE

$$\textit{Methane emissions} = CH_4 \textit{ Emission Factor} \bullet \textit{Surface Coal Production} \bullet \textit{Conversion Factor}$$

Where units are:

Methane Emissions (Gg $year^{-1}$)

CH_4 Emission Factor (m^3 $tonne^{-1}$)

Surface Coal Production (tonne $year^{-1}$)

Emissions Factor:

Low CH_4 Emission Factor = 0.3 m^3 $tonne^{-1}$

Average CH_4 Emission Factor = 1.2 m^3 $tonne^{-1}$

High CH_4 Emission Factor = 2.0 m^3 $tonne^{-1}$

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 0.67 ● 10^{-6} Gg m^{-3}.

For the Tier 1 approach, it is *good practice* to use the low end of the specific emission range for those mines with average overburden depths of less than 25 meters and the high end for overburden depths over 50 meters. For intermediate depths, average values for the emission factors may be used. In the absence of data on overburden thickness, it is *good practice* to use the average emission factor, namely 1.2 m^3/tonne.

The Tier 1 carbon dioxide emission factors are shown together with the estimation method in Equation 4.1.7.a

The emission factors are based on data reported to the Australian National Greenhouse and Energy Reporting program for years 2009-2017, measurements of gas in Kazakhstan surface mines and Japan National Inventory Report 2017. (RGE "Kaz NIIEK" MOOS RK 2010; Cook & Lloyd 2012; Commonwealth of Australia 2017; Ministry of the Environment Japan 2017; Ministry of Energy of the Republic of Kazakhstan 2017). The average emission factor is taken from the mean of the latest implied emission factors from each of these countries.

EQUATION 4.1.7A (NEW)
TIER 1: GLOBAL AVERAGE METHOD – SURFACE MINES – CARBON DIOXIDE
Carbon dioxide emissions = CO_2 Emission Factor ●Surface Coal Production ● Conversion Factor

Where units are:

Carbon dioxide Emissions (Gg $year^{-1}$)

CO_2 Emission Factor (m^3 $tonne^{-1}$)

Surface Coal Production (tonne $year^{-1}$)

Emissions Factor:

Low CO_2 Emission Factor = 0.01 m^3 $tonne^{-1}$

Average CO_2 Emission Factor = 0.44 m^3 $tonne^{-1}$

High CO_2 Emission Factor = 0.94 m^3 $tonne^{-1}$

Conversion Factor:

This is the density of CO_2 and converts volume of CO_2 to mass of CO_2. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 1.84 ● 10^{-6} Gg m^{-3} (GOST 2015).

For the Tier 1 approach, it is *good practice* to use the low end of the specific emission range for those mines with average overburden depths of less than 25 meters and the high end for overburden depths over 50 meters. Otherwise countries should use the average CO_2 emission factor of 0.44 m^3/tonne unless there is country-specific evidence to support use of an alternative factor within the low/high range.

The Tier 2 method uses the same equation as for Tier 1, but with data disaggregated to country-specific, or coal basin level. For countries using a Tier 2 approach, carbon dioxide emission factors may be obtained from sampling and analysis of gas content within carbonaceous strata of surface mines, prior to undertaking mining activities. The sampling and analysis of in-situ gas within rock strata should be undertaken according to relevant standards and procedures. Care needs to be taken to account for any degassing of the sample occurring between obtaining the sampling and the analysis of gas content.

POST-MINING EMISSIONS – SURFACE MINING

For a Tier 1 approach the post-mining emissions can be estimated using the emission factors shown in Equation 4.1.8.

EQUATION 4.1.8
TIER 1: GLOBAL AVERAGE METHOD – POST-MINING EMISSIONS – SURFACE MINES
Methane emissions = CH_4 Emission Factor ● Surface Coal Production ● Conversion Factor

Where units are:

Methane Emissions (Gg year^{-1})

CH_4 Emission Factor (m^3 tonne^{-1})

Surface Coal Production (tonne year^{-1})

Emission Factor:

Low CH_4 Emission Factor = 0 m^3 tonne^{-1}

Average CH_4 Emission Factor = 0.1 m^3 tonne^{-1}

High CH_4 Emission Factor = 0.2 m^3 tonne^{-1}

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 0.67 ● 10^{-6} Gg m^{-3}.

The average emission factor should be used unless there is country-specific evidence to support use of the low or high emission factor.

4.1.4.3 ACTIVITY DATA

No refinement.

4.1.4.4 COMPLETENESS FOR SURFACE MINING

No refinement.

4.1.4.5 DEVELOPING A CONSISTENT TIME SERIES

No refinement.

4.1.4.6 UNCERTAINTY ASSESSMENT IN EMISSIONS

EMISSION FACTOR UNCERTAINTY

Uncertainties in the emissions from surface mines are less well quantified than for underground mining. Briefly, the sources of the uncertainty are the same as described in Section 4.1.3.6 for underground coal mines. However, the variability in the emission factors for large surface mines may be expected to be greater than for underground coal mines, because surface mines can show significant variability across the extent of the mine as a result of local geological features.

Table 4.1.4 shows the Tier 1 and Tier 2 uncertainties associated with surface mining emissions.

TABLE 4.1.4 (UPDATED)
ESTIMATES OF UNCERTAINTY FOR SURFACE MINING FOR TIER 1 AND TIER 2 APPROACHES

Likely Uncertainties of Coal Mine Methane Emission Factors for Surface Mining (Expert Judgement*)		
Method	**Surface**	**Post-Mining**
Tier 2	Factor of 2 greater or lower	± 50%
Tier 1	Factor of 3 greater or lower	Factor of 3 greater or lower
GPG, 2000 - *IPCC Good Practice Guidance* and Uncertainty Management in National Greenhouse Gas Inventories (2000)		

Likely Uncertainties of Coal Mine Carbon Dioxide Emission Factors for Surface Mining *		
Method	**Surface**	**Post-Mining**
Tier 2	-50% to +100%	Not applicable
Tier 1	-67% to +200%	Not applicable
* Uncertainties set to be consistent with methane emission factors		

ACTIVITY DATA UNCERTAINTY

The comments made for underground mining in Section 4.1.3.6 also apply to surface mining.

4.1.5 Abandoned underground coal mines

No refinement exept Section 4.1.5.2.

4.1.5.1 CHOICE OF METHOD

No refinement.

4.1.5.2 CHOICE OF EMISSION FACTORS

Tier 1: Global Average Approach – Abandoned Underground Mines

A Tier 1 approach for determining emissions from abandoned underground mines is described below and is largely based on methods developed by the USEPA (Franklin et al, 2004). It incorporates a factor to account for the fraction of those mines that, when they were actively producing coal, were considered gassy. Thus, this methodology is based on the total number of coal mines abandoned, adjusted for the fraction considered gassy, as described below. Abandoned mines that were considered non-gassy when they were actively mined are presumed to have negligible emissions. In the US methodology, the term gassy mines referrs to coal mines that, when they were active, had average annual ventilation emissions that exceeded the range of 2 800 to 14 000 cubic meters per day (m^3/d), or 0.7 to 3.4 Gg per year.

The Tier 1 – approach for abandoned underground coal mines is as follows:

1. Determine the approximate time (year interval) from the following time intervals when gassy coal mines were abandoned:

   a. 1901 – 1925
   b. 1926 – 1950
   c. 1951 – 1975
   d. 1976 – 2000
   e. 2001 – present

2. Multiple intervals may be used where appropriate. It is recommended that the number of gassy coal mines abandoned during each time interval be estimated using the smallest time intervals possible based on available data. Ideally, for more recent periods, time intervals will decrease (e.g., intervals of ten years prior to 1990; annual intervals since 1990). Information for different coal mine-clusters abandoned during different time periods should be considered, since multiple time periods may be combined in the Tier 1 approach

3. Estimate the total number of abandoned mines in each time band since 1901 remaining unflooded. If there is no knowledge on the extent of flooding it is *good practice* to assume that 100 percent of mines remain

unflooded. For the purposes of estimating the number of abandoned mines, prospect excavations and hand cart mines of only a few acres in size should be disregarded.

4. Determine the percentage of coal mines that would be considered gassy at the time of mine closure. Based on the time intervals selected above, choose an estimated percentage of gassy coal mines from the high and low default values listed in Table 4.1.5. Actual estimates can range anywhere from 0 to 100 percent. When choosing within the high and low default values listed in Table 4.1.5, a country should consider all available historical information that may contribute to the percentage of gassy mines, such as coal rank, gas content, and depth of mining. Countries with recorded instances of gassy mines (e.g., methane explosions or outbursts) should choose the high default values in the early part of the century. From 1926 to 1975, countries where mines were relatively deep and hydraulic equipment was used should choose the high default value. Countries with deep longwall mines or with evidence of gassiness should choose the high values for the time periods after 1975. The low range of the default values may be appropriate for a given time interval for specific regions, coal basins, or nations, based on geologic conditions or known mining practices.

5. For the inventory year of interest (between 1990 and the present), select the appropriate emissions factor from Table 4.1.6. For example, for mines abandoned in the interval 1901 to 1925 and for the inventory reporting year 2005, the Emission Factor for these mines would have a value of 0.256 million m^3 of methane per mine.

6. Calculate for each time band the total methane emissions from Equation 4.1.10 to the inventory year of interest.

7. Sum the emissions for each time interval to derive the total abandoned mine emissions for each inventory year.

TABLE 4.1.5
TIER 1 – ABANDONED UNDERGROUND MINES -
DEFAULT VALUES - PERCENTAGE OF COAL MINES THAT ARE GASSY

Time Interval	Low	High
1900-1925	0%	10%
1926-1950	3%	50%
1950-1976	5%	75%
1976-2000	8%	100%
2001-Present	9%	100%

Final Draft

TABLE 4.1.6 (UPDATED)
TIER 1 – ABANDONED UNDERGROUND MINES - EMISSION FACTOR, MILLION M^3 METHANE / MINE

	Interval of mine closure					
Inventory Year	**1901 – 1925**	**1926 – 1950**	**1951 - 1975**	**1976 – 2000**	**2001 – 2025**	**2026 - 2050**
1990	0.281	0.343	0.478	1.561	NA	NA
1991	0.279	0.340	0.469	1.334	NA	NA
1992	0.277	0.336	0.461	1.183	NA	NA
1993	0.275	0.333	0.453	1.072	NA	NA
1994	0.273	0.330	0.446	0.988	NA	NA
1995	0.272	0.327	0.439	0.921	NA	NA
1996	0.270	0.324	0.432	0.865	NA	NA
1997	0.268	0.322	0.425	0.818	NA	NA
1998	0.267	0.319	0.419	0.778	NA	NA
1999	0.265	0.316	0.413	0.743	NA	NA
2000	0.264	0.314	0.408	0.713	NA	NA
2001	0.262	0.311	0.402	0.686	5.735	NA
2002	0.261	0.308	0.397	0.661	2.397	NA
2003	0.259	0.306	0.392	0.639	1.762	NA
2004	0.258	0.304	0.387	0.620	1.454	NA
2005	0.256	0.301	0.382	0.601	1.265	NA
2006	0.255	0.299	0.378	0.585	1.133	NA
2007	0.253	0.297	0.373	0.569	1.035	NA
2008	0.252	0.295	0.369	0.555	0.959	NA
2009	0.251	0.293	0.365	0.542	0.896	NA
2010	0.249	0.290	0.361	0.529	0.845	NA
2011	0.248	0.288	0.357	0.518	0.801	NA
2012	0.247	0.286	0.353	0.507	0.763	NA
2013	0.246	0.284	0.350	0.496	0.730	NA
2014	0.244	0.283	0.346	0.487	0.701	NA
2015	0.243	0.281	0.343	0.478	0.675	NA
2016	0.242	0.279	0.340	0.469	0.652	NA
2017	0.241	0.277	0.336	0.439	0.625	NA
2018	0.239	0.275	0.333	0.432	0.604	NA
2019	0.238	0.273	0.330	0.425	0.586	NA
2020	0.237	0.272	0.327	0.419	0.569	NA
2021	0.236	0.270	0.324	0.413	0.555	NA
2022	0.235	0.268	0.322	0.408	0.542	NA
2023	0.234	0.267	0.319	0.402	0.529	NA
2024	0.233	0.265	0.316	0.397	0.518	NA
2025	0.232	0.264	0.314	0.392	0.507	NA
2026	0.23	0.262	0.311	0.387	0.496	5.735
2027	0.229	0.261	0.308	0.382	0.487	2.397
2028	0.228	0.259	0.306	0.378	0.478	1.762
2029	0.227	0.258	0.304	0.373	0.469	1.454
2030	0.226	0.256	0.301	0.369	0.439	1.265
2031	0.225	0.255	0.299	0.365	0.432	1.133
2032	0.224	0.253	0.297	0.361	0.425	1.035
2033	0.223	0.252	0.295	0.357	0.419	0.959
2034	0.223	0.251	0.293	0.353	0.413	0.896
2035	0.222	0.249	0.290	0.350	0.408	0.845
2036	0.221	0.248	0.288	0.346	0.402	0.801
2037	0.220	0.247	0.286	0.343	0.397	0.763
2038	0.219	0.246	0.284	0.340	0.392	0.730
2039	0.218	0.244	0.283	0.336	0.387	0.701
2040	0.217	0.243	0.281	0.333	0.382	0.675
2041	0.216	0.242	0.279	0.330	0.378	0.652
2042	0.215	0.241	0.277	0.327	0.373	0.625
2043	0.214	0.239	0.275	0.324	0.369	0.604
2044	0.214	0.238	0.273	0.322	0.365	0.586
2045	0.213	0.237	0.272	0.319	0.361	0.569
2046	0.212	0.236	0.270	0.316	0.357	0.555
2047	0.211	0.235	0.268	0.314	0.353	0.542
2048	0.210	0.234	0.267	0.311	0.350	0.529
2049	0.210	0.233	0.265	0.308	0.346	0.518
2050	0.209	0.232	0.264	0.306	0.343	0.507

As abandoned underground mines are included for the first time an example calculation has been included in Table 4.1.7.

TABLE 4.1.7 (UPDATED)
TIER 1 – ABANDONED UNDERGROUND MINES - EXAMPLE CALCULATION

	Interval of mine closure					
	1901 – 1925	**1926 – 1950**	**1951 - 1975**	**1976 – 2000**	**2001 – Present**	**Total for inventory year 2005**
Number of mines closed per time band	20	15	10	5	1	
Fraction of gassy mines	0.1	0.5	0.75	1.0	1.0	
Emission factor for Inventory year, 2005 (from Table 4.1.6)	0.256	0.301	0.382	0.601	1.265	
Total emissions (Gg CH_4 per year from Equation 4.1.10)	0.34	1.51	1.92	2.07	0.85	6.64

Tier 2 – Country- or Basin-Specific Approach

The Tier 2 approach for developing an abandoned mine methane emission inventory follows a similar approach to Tier 1, but it incorporates country- or basin-specific data. The methodology presented below is intended to utilize coal basin-specific or country-specific data wherever possible (for example, for active mine emissions prior to abandonment, for basin-specific parameters for emissions factors, etc.).

In some cases, default parameters have been provided for these values but these should be used only if country-specific or basin-specific data are not available.

Calculate emissions for a given inventory year using Equation 4.1.11:

EQUATION 4.1.11
TIER 2 APPROACH FOR ABANDONED UNDERGROUND MINES WITHOUT METHANE RECOVERY AND UTILIZATION

Methane Emissions = Number of Coal Mines Abandoned Remaining Unflooded ● Fraction of Gassy Mines ● Average Emissions Rate ● Emission Factor ● Conversion Factor

Where units are:

Emissions of methane (Gg $year^{-1}$)

Emission Rate (m^3 $year^{-1}$)

Emission Factor (dimensionless, see Equation 4.1.11)

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6}$ Gg m^{-3}

If individual mines are known to be completely flooded, they may be assigned an emissions value of zero. Methane emissions reductions due to recovery projects that utilize or flare methane at abandoned mines should be subtracted from the emissions estimate. For either of these cases, it is recommended that a hybrid Tier 2 – Tier 3 approach be used to incorporate such mine-specific information (see the discussion of methane recovery and utilization projects from abandoned mines, Sections 4.1.5.1 and 4.1.5.3).

The basic steps in the Tier 2 approach for abandoned underground coal mines are as follows:

- Determine the approximate time interval(s) when significant numbers of gassy coal mines were closed. Multiple intervals may be used where appropriate. It is recommended that the number of gassy coal mines abandoned during each time interval be estimated using the smallest time intervals possible based on available data. Ideally, for more recent periods, time intervals will decrease (e.g., intervals of ten years prior to 1990; annual intervals since 1990).
- Estimate the total number of abandoned mines in each time interval selected remaining unflooded. If there is no available information on the flooded status of the abandoned mines, assume 100 percent remain unflooded.
- Determine the number (or percentage) of coal mines that would be considered gassy at the time of mine closure.

- For each time interval, determine the average emissions rate. If country or basin-specific data do not exist, low and high estimates for active mine emissions prior to abandonment can be selected from Table 4.1.8.
- For each time interval, calculate an appropriate emissions factor using Equation 4.1.12, based on the difference in years between the estimated data of abandonment and the year of the emissions inventory. Note that default values for this emissions factor equation are provided in Table 4.1.9, but these default values should be used only where country- or basin-specific information are not available.
- Calculate the emissions for each time interval using Equation 4.1.11.
- Sum the emissions for each time interval to derive the total abandoned mine emissions for each inventory year.

TABLE 4.1.8
TIER 2 – ABANDONED UNDERGROUND COAL MINES -
DEFAULT VALUES FOR ACTIVE MINE EMISSIONS PRIOR TO ABANDONMENT

Parameter	Emissions, million m^3/yr
Low	1.3
High	38.8

EQUATION 4.1.12
TIER 2 – ABANDONED UNDERGROUND COAL MINES EMISSION FACTOR

$$Emission\ Factor = (1 + aT)^b$$

Where:

a and *b* are constants determining the decline curve. Country or basin-specific values should be used wherever possible. Default values are provided in Table 4.1.9, below.

T = years elapsed since abandonment (difference of the mid point of the time interval selected and the inventory year) and inventory year.

A separate emission factor must be calculated for each time interval selected. This emission factor is dimensionless.

TABLE 4.1.9
COEFFICIENTS FOR TIER 2 – ABANDONED UNDERGROUND COAL MINES

Coal Rank	A	b
Anthracite	1.72	-0.58
Bituminous	3.72	-0.42
Sub-bituminous	0.27	-1.00

Tier 3-Mine-Specific Approach

Tier 3 provides a great deal of flexibility. Directly measured emissions, where available, can be used in place of estimates and calculations. Models may be used in conjunction with measured data to estimate time series emissions. Each country may generate their own decline curves or other characterizations based on measurements, known basin-specific coal properties, and/or hydrological models. Equation 4.1.13 describes one possible, approach.

EQUATION 4.1.13
EXAMPLE OF TIER 3 EMISSIONS CALCULATION – ABANDONED UNDERGROUND MINES

Methane Emissions = (Emission rate at closure ● Emission Factor ● Conversion Factor) – Methane Emissions Reductions from Recovery and Utilisation

Where units are:

Methane Emissions (Gg $year^{-1}$)

Emission rate at Closure (m^3 $year^{-1}$)

Emission Factor (dimensionless, see Franklin *et al*., 2004)

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 0.67 ● 10^{-6} Gg $m^{-3.}$

The basic steps in the Tier 3 methodology involve the following:

- Determine a database of mine closures with relevant geological and hydrological information and the approximate abandonment dates (when all active mine ventilation ceased) consistently for all mines in the country's inventory.
- Estimate emissions based on measured emissions and/or an emissions model. This may be based on the average emission rate at time of mine closure, determined by the last measured emission rate (or preferably, an average of several measurements taken the year prior to abandonment), or estimated methane reserves susceptible to release.
- If actual measurements have not been taken at a given mine, emissions may be calculated using an appropriate decline curve or modelling approach for openly vented mines, sealed mines, or flooded mines. Use the selected decline equation or modelling approach for the mine and the number of years between abandonment and the inventory year to calculate emissions or an appropriate emission factor for each mine.
- Sum abandoned mine emissions to develop an annual inventory.

4.1.5.3 CHOICE OF ACTIVITY DATA

No refinement.

4.1.5.4 COMPLETENESS

No refinement.

4.1.5.5 DEVELOPING A CONSISTENT TIME SERIES

No refinement.

4.1.5.6 UNCERTAINTY ASSESSMENT

No refinement.

4.1.6 Coal Exploration

4.1.6.1 CHOICE OF METHOD

Fugitive methane emissions from exploration boreholes in a coalfield depend on the gas content, cumulative thickness of the coal seams encountered during exploratory drilling, as well as stratigraphy, structure and nature of coal and associated sediments. A variety of geological and geophysical techniques such as generating a geological map of the area, carrying out geochemical and geophysical surveys, drilling of exploration boreholes with or without coring, down-hole geophysical logging and comprehensive analysis and testing of core samples are used to estimate the coal resources. While drilling for coal exploration programs involve core and/or non-core drilling, core drilling is the only satisfactory means of obtaining representative samples (Ward, 2009), either of coal seams for thickness and quality assessment or of non-coal rocks for geotechnical tests. Emissions from coal exploration covered here include those fugitive emissions from the drilling of exploration boreholes.

Emission of methane from exploratory boreholes directly depends on number of exploration boreholes drilled in a reporting period. When considering a borehole-specific approach, there is a need to ensure the source boundary distinction between boreholes that are drilled as part of coal mine production (which are already included as part of Underground and Surface coal mining activities) and those drilled for coal exploration to avoid double counting.

Field level desorption tests are carried out during exploratory drilling of some selected boreholes and important CBM related data such as *In-situ* gas content, sorption time etc. are generated (CMPDI, 2016). Gas desorption curves are also prepared. Often adsorption isotherm curves are also constructed. National emission factors can be evaluated using the measured data in and mathematical models for gas flow rates from a well without any stimulation. The emission factors so evaluated can be used for estimation of emission from every borehole drilled in a coal block. Therefore, substantial research and development opportunities should be explored to find number of exploratory boreholes drilled in a reporting period which may be obtained from geological reports on coal exploration for numerous coal blocks. Emission factors may also be calculated for each of the blocks. Estimates of fugitive methane emission should then be prepared with a high degree of accuracy. Nevertheless, exploration involves many agencies in a country and geological reports on exploration are not usually readily available in exploration reports or any other publication.

However, annual updating of the national quantity of coal and lignite resources is an integral part of exploration often used to update the national quantity of coal and lignite resources. Annual national inventories of coal and lignite resources are often prepared by a single ministry or nodal agency of the country. Therefore, augmentation of coal resources (GSI, 2017) in a reporting year over that of the preceding year can be easily obtained or calculated by subtracting the resources of the current year from that of the preceding year. This annual change or augmentation may be used as activity data for exploration boreholes if number of boreholes drilled in a reporting period is not available.

While the required coal data is often available on a yearly basis for major coal producing countries, annual data on "resource augmentation" may not be available or may be available on a decade by decade basis in the national statistics. Global statistical publications like BP Statistical Review of World Energy may be referred to in such circumstances.

The augmentation of coal resources is the additional resource of coal and lignite found as a result of exploration during a reporting year which, when added to the previous year's resource, gives current resource. The entire augmented resources are not the sources of greenhouse gas emission but they indirectly represent the number of coal exploration boreholes since the exploratory drilling is usually carried at known interval over coal bearing areas for assessment of coal potentiality. The spacing of the boreholes depends on geological structure, deposit character, nature of data required for mine planners etc. Although seismic exploration technology is very important for petroleum exploration, it is seldom used in exploration of solid minerals such as coal due to technological and economic limitations (National Research Council 2002). Instead, drilling of exploratory boreholes that yields a plethora of information on coal characteristics and resources is very common for exploration of coal.

Figure 4.1.4 is a decision tree that shows how to determine which tier to use.

Tier 1 – Global Average Approach – Fugitive Emission from Coal Exploration Boreholes

For a Tier 1 approach the estimation method may be expressed in the form of an equation given below:

EQUATION 4.1.14 (NEW)
TIER 1: GLOBAL AVERAGE METHOD – FUGITIVE EMISSION FROM COAL EXPLORATION BOREHOLES

$$\text{Methane emissions from a coal seam at a depth} = CH_4 \text{ Emission Factor for the depth} \bullet \text{Augmentation of Resource for the depth} \bullet \text{Conversion Factor}$$

$$\text{Methane Emission from Exploration} = \sum_1^3 \text{Methane Emission from coal seams in three different ranges of depths}$$

Where units are:

Methane Emissions (Gg $year^{-1}$)

CH_4 Emission Factor (m^3 $tonne^{-1}$)

Augmentation of Resource (tonne $year^{-1}$)

All different categories of coal resources such as measured (or proved), indicated and inferred etc. (UNFC 2009), should be taken into account for determining activity data of augmented resource. Care should be taken if there is a reduction in the coal resource quantity in a reporting period in which case the method may produce a negative emission in that year. This should be treated as an undesirable outcome and unusual observation for which Tier 1 method should not be used. In such a situation, emission should be regarded as zero emission instead be negative emission.

Tier 2 – Basin-Specific Approach

The Tier 2 approach for preparing a methane emission inventory from coal exploration boreholes is similar to the Tier 1 method, but basin-specific borehole data are taken into consideration in a Tier 2 method. Coal basin-specific data on methane emission from exploratory boreholes in a basin or coalfield should be collected. The average value of such measured emissions from some boreholes, if available, should be considered as emission factor for the basin under consideration. The emission factor so evaluated should be multiplied by number of boreholes drilled in the basin under consideration to arrive at the emission from the basin. Similarly, methane emission from other basins should also be estimated. Tier 1 method should be adopted for those basins where no measurement has been done from any exploratory borehole. Summation of the emission values from each of the basins gives the emission estimate from exploratory boreholes for the country.

For a Tier 2 approach the exploration borehole emission estimation method is shown below:

EQUATION 4.1.15 (NEW)
TIER 2: BASIN-SPECIFIC METHOD

Methane emissions from a basin or coalfield = Number of boreholes drilled in the basin ● CH_4 Emission Factor for the basin ● Conversion Factor

$$Methane\ Emission\ from\ Exploration = \sum_1^n Methane\ Emission\ from\ coal\ seams\ in\ the\ basin$$

Where n = number of basins and units are:

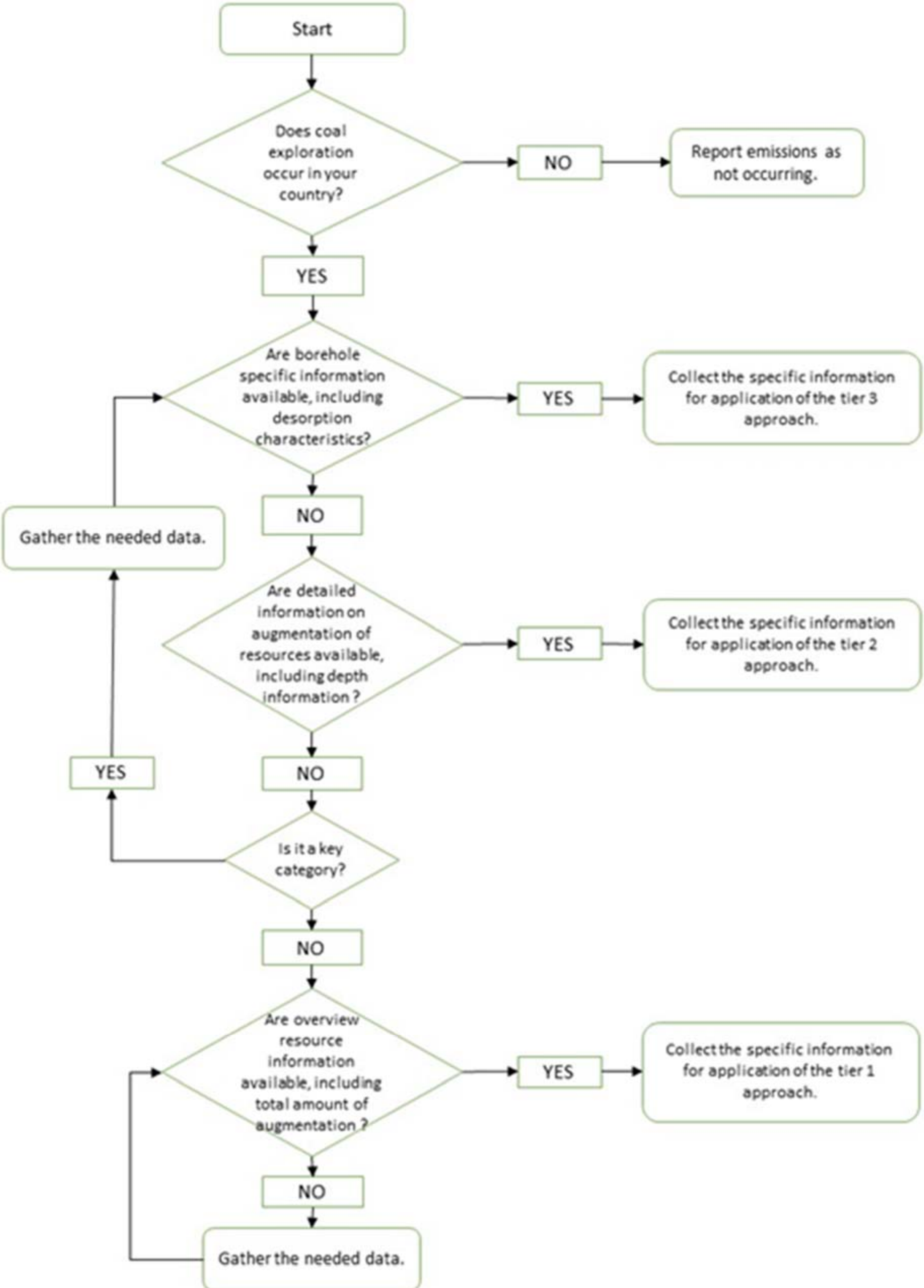
Methane Emissions (Gg $year^{-1}$)

CH_4 Emission Factor (m^3 $tonne^{-1}$)

Tier 3 – Borehole Specific Approach

Coal exploration companies often determine in-situ gas content and other gas desorption characteristics such as sorption time of coal seams encountered during exploratory drilling of boreholes, Langmuir volume, Langmuir pressure and permeability. Release of gas from a coal seam is highly dependent on these parameters. Models are also available to calculate emissions if the gas desorption parameters are available. The impact of management actions such as borehole capping etc. should be taken into consideration. A Tier 3 approach can be developed if gas desorption parameters are available. When considering a borehole-specific approach, there is a need to ensure the source boundary distinction between boreholes that are drilled as part of coal mine production (which are already included as part of Underground and Surface coal mining activities) and those drilled for coal exploration to avoid double counting.

Figure 4.1.4 (New) Decision tree for coal exploration



4.1.6.2 CHOICE OF EMISSION FACTORS

No information is found in the literature on measurement of fugitive methane emission specifically from coal exploration boreholes. Therefore emission factors provided below are as per expert opinion. Since the exploration boreholes are filled with water or mud, the hydrostatic pressure on the coal seams encountered will be significant. Accordingly, emission factors for exploration boreholes are assumed to be small compared to those of other coal mining activities.

Tier 1 – Global Average Approach – Fugitive Emission from Coal Exploration Boreholes

Default emission factors for different depth ranges given below and activity data on augmented resource in the respective depth range should be used for calculation of emission estimates using Equation 4.1.14. It should be noted that the entire resource shall not emit methane but only a fraction of it will release the gas. Therefore, emission factors for exploration boreholes are very less in comparison to the emission factors for underground mining and post mining activities prescribed in Equations 4.1.3 and 4.1.4. This will correspond to emission from coal very closed to the well bore.

CH_4 Emission Factor = 0.01 m^3 $tonne^{-1}$ for depth range 0 – 600 m

CH_4 Emission Factor = 0.03 m^3 $tonne^{-1}$ for depth range 600 – 1200 m

CH_4 Emission Factor = 0.05 m^3 $tonne^{-1}$ for depth > 1200 m

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6}$ Gg m^{-3}.

The basis of arriving at the above emission factors is expert judgment since information on fugitive methane emission from coal exploration boreholes is not usually readily available. It is well known that *in-situ* gas content of coal seams increases with depth. Therefore, deeper coal horizons are likely to emit at higher rates. Hence, emission factor will be higher for deeper seams. Further, exploration boreholes are filled with water or mud which does not allow coal seams to release gases adsorbed on coal surface at faster rates as in the case of coal faces in underground or surface mines. The emission factors are only a fraction of the corresponding emission factors for surface and underground coal mining.

Tier 2 – Basin-Specific Approach

For a Tier 2 approach the exploratory borehole emissions factors may be evaluated as described below:

Emission Factor:

Information about basins or coalfields wherever methane emission measurements from coal exploration boreholes have been conducted, should be collected first. Average value of the emission (m^3) from accessible data in the basin should be calculated to evaluate methane emission per exploration borehole (m^3/exploratory borehole). This value of methane emission per exploration borehole should be used as emission factor (m^3/exploratory borehole) for the basin which should be multiplied by the number of exploration boreholes drilled in the basin to obtain volume of fugitive methane emission (m^3) from exploratory boreholes drilled in the basin. Tier 1 emission default emission factors may be used for the basins or coalfields wherever number of exploration boreholes drilled are unknown or emission factor as described above cannot be evaluated.

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6}$ Gg m^{-3}.

Tier 3 – Borehole Specific Approach

Coal exploration companies often determine in-situ gas content and other desorption characteristics such as sorption time of coal seams encountered during exploratory drilling of boreholes, Langmuir volume, Langmuir pressure and permeability etc.. Release of gas from a coal seam is highly dependent on these parameters. Models are also available to calculate emissions if the gas desorption parameters are available. A Tier 3 approach can be developed if gas desorption parameters are available.

4.1.6.3 CHOICE OF ACTIVITY DATA

Augmentation of resources or new addition of resources in the year may be used as activity data, which may be available in the inventory of coal or lignite resources or can be easily obtained by subtracting the resources for a year and the resources for the previous year as follows:

Augmentation or New Addition = Resource for a year – Resource for the previous year

The above activity data may be used for Tier 1 estimates. A precise value for activity data may be available for net increase of depth-wise resource. Often coal resources are reported in the depth ranges such as 0-600 m and 600-1200 m and higher than 1200 m. Since gas content of coal seams generally increases with depth, emission from deeper seams will be higher compared to the seams at shallow depths. These values of activity data correspond to Tier 1 estimates.

Number of exploration boreholes drilled in a reporting period will be used as activity data for Tier 2 and Tier 3 methods.

4.1.6.4 COMPLETENESS

Exploration for coal is generally carried out in two broad categories, often called as Regional and Detailed Exploration. During regional exploration, coal resources of inferred or indicated categories using data obtained from boreholes few kilometres apart (typically 2 to 4 km) are estimated. Detailed exploration is carried out to arrive at measured or proved resource using data from boreholes normally drilled less than a kilometre apart (typically 400 m). The number and distribution of boreholes during detailed exploration are sufficient to allow a realistic estimate of average coal thickness, areal extent, depth range, quality and mineable reserve of coal. The estimate of fugitive methane emission from coal exploration boreholes should include all emissions from the following:

- Gas released from boreholes during regional exploration
- Emission of gas from boreholes during detailed exploration

4.1.6.5 DEVELOPING A CONSISTENT TIME SERIES

Time series consistency should be maintained in a manner consistent with guidance set out in Volume 1, Chapter 5.

A complete borehole specific data may not be available for the base year and also for the succeeding years. It may be imperative, therefore, to prepare a combination of Tier 1, Tier 2 and Tier 3 estimates.

If Tier 2 or Tier 3 methods are used for exploration boreholes for certain inventory years, emissions should be scaled-up or scaled-down for the remaining years using an appropriate value (low, average or high) of Tier 1 emission factor.

4.1.6.6 UNCERTAINTY ASSESSMENT

ACTIVITY DATA UNCERTAINTIES

The activity data of resource augmentation in Tier 1 method is reasonably accurately known (±5 percent). However, there may be uncertainties on account of extrapolation techniques used for estimation of inferred and indicated categories of coal resources. Thus, combining the errors in estimation of different category of resources (such as proved, inferred and indicated), the activity data of resource augmentation may have an uncertainty of ±10 percent. In borehole specific approach (Tier 3 method), where number of boreholes, number of coal seams encountered, their thicknesses and *in-situ* gas content etc. are known, uncertainty may be in the range of ±1 – 2 percent.

EMISSION FACTOR UNCERTAINTIES

Uncertainties in Tier 1 approach mainly arise because of use of global emission factors. There may be some intrinsic uncertainties in the emission factors as well. As combination of these effects, the uncertainties in Tier 1 approach may be greater or smaller by a factor of 3, that is actual emissions are likely to be in the range of one-third to three times of the estimated value of fugitive methane emission.

Tier 2 estimates may also have liability to vary due to inherent uncertainties associated with basin level characteristics. Uncertainties in Tier 2 approach may be ±75-100%.

Coal characteristics, *in-situ* gas content and other gas desorption parameters are often determined for a selected number of exploration boreholes. These parameters vary considerably in lateral directions in an exploration field. Tier 3 estimates may be accurate to ±50 percent depending on number of boreholes tested for gas desorption parameters.

4.1.7 Completeness for coal mining

Several sources have been identified with potential emissions, but are not included with a methodology in these guidelines. These are abandoned surface mines and uncontrolled combustion and burning coal deposits.

ABANDONED SURFACE MINES

After closure, emissions from abandoned surface mines may include the following:

- The standing highwall
- Leakage from the pit floor
- Low temperature oxidation
- Uncontrolled combustion

At present, no comprehensive methods to quantify these emissions have been developed and therefore they have not been included in these guidelines. They remain subjects for further research.

EMISSIONS FROM UNCONTROLLED COMBUSTION AND BURNING COAL DEPOSITS

While emissions from this source may be significant for an individual coal mine, it is unclear as to how significant these emissions may be for an individual country. In some countries where such fires are widespread, the emissions may be very significant. There are no clear methods available at present to systematically measure or precisely estimate the activity data, though where countries have data on amounts of coal burned, the CO_2 should be estimated on the basis of the carbon content of the coal and reported in the relevant subcategory of 1.B.1.b. It is noted that uncontrolled combustion only due to coal exploration activities is considered here. Care should be taken to avoid double counting with fugitive CH_4 and low oxidation CO_2 emissions.

4.1.8 Inventory Quality Assurance/Quality Control (QA/QC)

No refinement.

4.2 FUGITIVE EMISSIONS FROM OIL AND NATURAL GAS SYSTEMS

This section is an update of Section 4.2 in Vol.2 of the *2006 IPCC Guidelines*. Fugitive emissions from oil and natural gas systems are accounted for in IPCC subcategory 1.B.2 of the energy sector. For reporting purposes, this category is subdivided as shown in Figure 4.2.0. The main distinction is made between oil and natural gas systems, with each being subdivided into the different parts (or segments) of the oil or gas system according to the type of activity[2]. Fuel gases other than natural gas, such as town gas[3] and biogas, are often handled in natural gas systems (such as transmission and distribution systems), and are discussed here as well. Where coalbed methane is delivered into a natural gas system, any associated fugitive emissions should be reported under the appropriate natural gas exploration and production categories.

The term fugitive emissions is broadly applied here to mean all greenhouse gas emissions from oil and gas systems except contributions from fuel combustion. Fugitive emissions include vented emissions, leak emissions, and flaring emissions. Oil and natural gas systems comprise all infrastructure required to produce, collect, process or refine and deliver natural gas and petroleum products to market. The system begins during the exploration process, which includes all fugitive emissions associated with activities such as prospecting and/or exploratory drilling, well testing, field development and well development (construction to completion, fracture stimulation), and ends at the consumer (including fugitive emissions between gas meters and appliances, but not from appliance start-stop losses or appliance combustion). Emissions excluded from this category are as follows:

- Fuel combustion for the production of useful heat or energy by stationary or mobile sources (see Chapters 2 and 3 of the Energy Volume).
- Fugitive emissions from carbon capture and storage projects, the transport and disposal of acid gas from oil and gas facilities by injection into secure underground formations, or the transport, injection and sequestering of CO_2 as part of enhanced oil recovery (EOR), enhanced gas recovery (EGR) or enhanced coal bed methane (ECBM) projects (see Chapter 5 of the Energy Volume on carbon dioxide capture and storage systems). Note that fugitive emissions from the oil and gas production portions of EOR, EGR and ECBM projects are part of Category 1.B.2.
- Fugitive emissions that occur at industrial facilities other than oil and gas facilities (see the Industrial Processes and Product Use Volume).
- Fugitive emissions from waste disposal activities that occur outside the oil and gas industry (see the Waste Volume).
- Where a coal formation is degassed for coal exploration or coal mining and handling, the associated emissions should be allocated to the coal sector under the appropriate section of IPCC category 1.B.1.

When determining fugitive emissions from oil and natural gas systems, it may be necessary to apply greater disaggregation than is shown in Figure 4.2.0 to better account for local factors affecting the amount of emissions (i.e., reservoir conditions, processing/treatment requirements, design and operating practices, age of the industry, market access, regulatory requirements and the level of regulatory enforcement), and to account for changes in activity levels in progressing through the different parts of the system. The percentage contribution by each category in Figure 4.2.0 to total fugitive emissions by the oil and gas sector will vary according to the amount of oil and gas produced, consumed, imported and exported, and according to technologies and practices in place in different segments that may increase or decrease emissions. Some examples of the potential distribution of fugitive emissions by subcategory are provided in (American Petroleum Institute (API) 2009).

[2] Definitions for oil wells versus gas wells can vary from country to country and organization to organization. Guidance for making this distinction when applying tier 1 factors is available in Section 4.2.2.3 below.

[3] Town gas (also called coal gas) is a manufactured gaseous fuel produced for sale to commercial and residential consumers. The guidelines assume that town gas contains hydrogen (around 50%), carbon monoxide (around 10%), methane (around 35%) and volatile hydrocarbons (around 5%) together with carbon dioxide and nitrogen (each less than 1%). It was used in Europe until the end of the last millennium and is still used in China (Zheng *et al*. 2010).

4.2.1 Overview, description of sources

The sources of fugitive emissions on oil and gas systems include, but are not limited to, equipment leaks, evaporation and flashing losses, venting, flaring and accidental releases (e.g., pipeline dig-ins, well blow-outs and spills). Venting and flaring emission sources are engineered or intentional (e.g., vents from tanks, seal and process vents and flare systems), while leak emissions (e.g. working losses from tanks, and leaks from other equipment) are unintentional (or uncontrolled). Some emissions are relatively well-characterized, with use of measurement systems in certain cases, where losses or flows are tracked as part of routine production accounting procedures, or where engineering estimates are made. Uncertainties associated with such estimates include those due to an inability to cover the wide range of flows and variations in composition that may occur, and inconsistencies in the activities that are included. A lack of data on activities and practices in place in a country can also contribute to uncertainty. Throughout this chapter, an effort is made to state the precise type of fugitive emission source being discussed, and to only use the term fugitive emissions or fugitive emission sources when discussing these emissions or sources at a higher, more aggregated, level.

Streams containing pure or high concentrations of CO_2 may occur at oil production facilities where CO_2 is being injected into an oil reservoir for EOR, ECBM or EGR. They may also occur at gas processing, oil refining and heavy oil upgrading facilities as a by-product of gas treating to meet sales or fuel gas specifications, and at refineries and heavy oil upgraders as a by-product of hydrogen production. Where CO_2 occurs as a process by-product it is usually vented to the atmosphere, injected into a suitable underground formation for disposal or supplied for use in EOR projects. Fugitive CO_2 emissions from these streams should be accounted for under the appropriate subcategories of 1.B.2. Fugitive CO_2 emissions from CO_2 capture should be accounted for in the industry where capture occurs, while the fugitive CO_2 emissions from transport, injection and storage activities shall be accounted for separately in category 1.C (refer to Chapter 5).

EOR is the recovery of oil from a reservoir by means other than using the natural reservoir pressure. It can begin after a secondary recovery process or at any time during the productive life of an oil reservoir. EOR generally results in increased amounts of oil being removed from a reservoir in comparison to methods using natural pressure or pumping alone. The three major types of enhanced oil recovery operations are chemical flooding (alkaline flooding or micellar-polymer flooding), miscible displacement (CO_2 injection or hydrocarbon injection), and thermal recovery (steamflood or *in-situ* combustion).

Emissions from oil and gas exploration are disaggregated to reflect that unconventional completions (e.g., conducted with hydraulic fracturing[4]) have a different emissions profile than conventional completions (e.g. conducted without hydraulic fracturing). Conventional reservoirs are those in which hydrocarbons are sealed below a capstone and from which hydrocarbons readily flow due to natural buoyant forces. Unconventional reservoirs, such shale and tight gas, are those for which their characteristics (e.g. porosity, permeability) differ from conventional reservoirs. In the case of unconventional resources, additional techniques, such as hydraulic fracturing, are required to stimulate the release and flow of oil and gas from low-permeability unconventional formations such as shale. Tier 1 emission factors and methods for calculating emissions from oil and gas exploration are differentiated by whether or not hydraulic fracturing is conducted, regardless of formation type. Different hydraulic fracturing practices can greatly impact emissions levels. For example, hydraulic fracturing completions with flaring or reduced emissions completions (REC) technologies will have lower emissions than completions without those practices. In this chapter, unconventional exploration refers to exploration that includes well completions with hydraulic fracturing and conventional exploration refers to exploration that does not include well completions with hydraulic fracturing.

[4] There are potential other types of unconventional exploration (e.g. hydrates) but currently hydraulic fracturing is the most common type of unconventional exploration. Emission factors for unconventional exploration were developed from data from hydraulic fracturing.

Figure 4.2.0 (New) Key segments included in oil and natural gas systems

For a detailed description of each segment, please see Section 4.2.2.3, Choice of Emission Factors, below. Note: this diagram provides examples of activities included in the segments of oil systems; it is not intended as a flow chart or supply chain diagram.

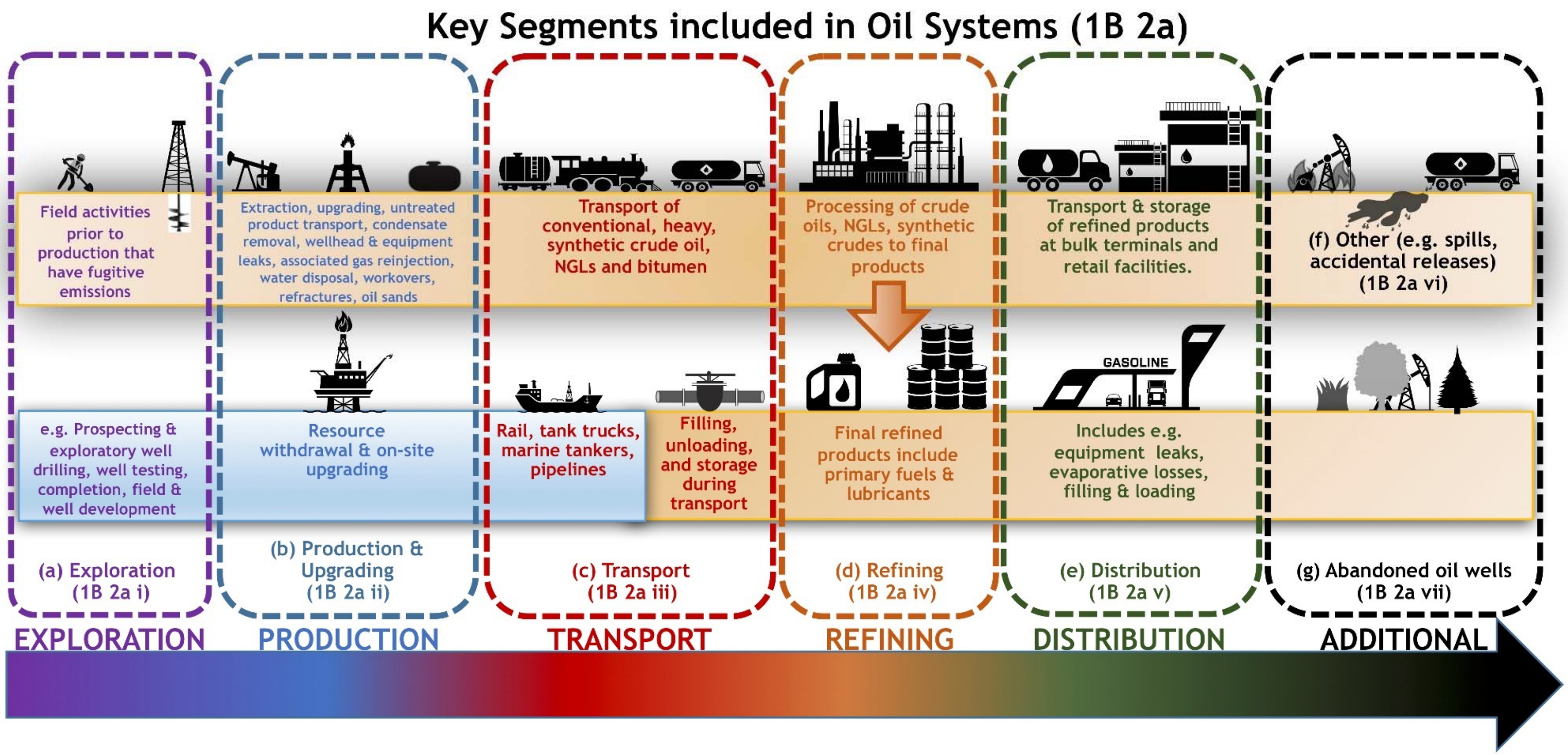
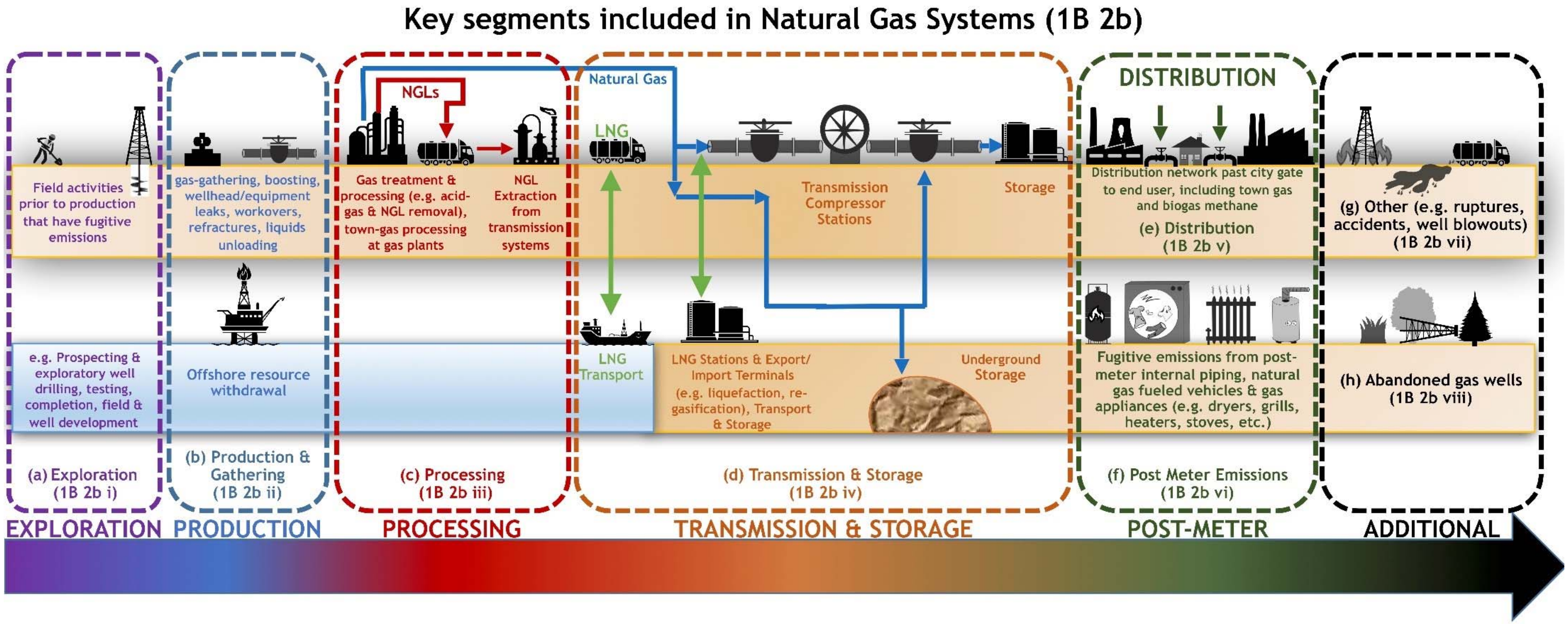


Figure 4.2.0 (New) (Continued) Key segments included in oil and natural gas systems

For a detailed description of each segment, please see Section 4.2.2.3, Choice of Emission Factors, below. Note: this diagram provides examples of activities included in the segments of natural gas systems; it is not intended as a flow chart or supply chain diagram.



4.2.2 Methodological issues

Fugitive emissions are a direct source of greenhouse gases due to the release of methane (CH_4) and formation carbon dioxide (CO_2) (i.e., CO_2 present in the produced oil and gas when it leaves the reservoir), plus some CO_2 and nitrous oxide (N_2O) from non-productive combustion activities (primarily waste gas flaring). In this chapter, fugitive emissions include emissions from venting, flaring, and leaks.

Venting comprises all engineered or intentional discharges of waste gas streams and process by-products to the atmosphere, including emergency discharges. These releases may occur on either a continuous or intermittent basis, and may include the following:

- Use of pressurized natural gas instead of compressed air as the supply medium for pneumatic devices (e.g., chemical injection pumps, starter motors on compressor engines and instrument control loops).
- Pressure relief and disposal of off-specification product during process upsets.
- Purging and blowdown events related to maintenance and tie-in activities.
- Disposal of off-gas streams from oil and gas treatment units (e.g., still-column off-gas from glycol dehydrators, emulsion treater overheads and stabilizer overheads).
- Gas releases from drilling, well-testing and pipeline pigging activities.
- Disposal of waste associated gas at oil production facilities and casing-head gas at heavy oil wells where there is no gas conservation, re-injection, or flaring.
- Solution gas emissions from storage tanks, evaporation losses from process sewers, API separators, dissolved air flotation units, tailings ponds and storage tanks, and biogenic gas formation from tailings ponds.
- Discharge of CO_2 extracted from the produced natural gas or produced as a process byproduct.

Some or all of the vented gas may be captured for storage or utilization. In this instance, the inventory of vented emissions should include only the net emissions to the atmosphere.

Flaring means broadly all burning of waste natural gas and hydrocarbon liquids by flares or incinerators as a disposal option rather than for the production of useful heat or energy. The decision on whether to vent or flare depends largely on the amount and energy content of gas to be disposed of and the specific circumstances (e.g., public, environmental and safety issues as well as local regulatory requirements). Normally, waste gas is only vented if it is non-odourous and non-toxic, and even then may often be flared. Flaring is most common at production, processing, upgrading and refining facilities but may occur in other segments as well. Waste gas volumes are usually vented on gas transmission systems and may be vented on gas distribution systems, depending on the circumstances and the company's policies. Sometimes fuel gas may be used to enrich a waste gas stream so it will support stable combustion during flaring. Fuel gas may also be used for other purposes where it may ultimately be vented or flared, such as purge or blanket gas and supply gas for gas-operated devices (e.g., for instrument controllers). The emissions from these types of fuel uses should be reported under the appropriate venting and flaring subcategories rather than under Category 1.A (Fuel Combustion Activities).

Formation CO_2 removed from natural gas by the sweetening units at gas processing plants (i.e. for acid gas removal) and released to the atmosphere is a fugitive emission and should be reported under subcategory 1.B.2.b.iii The CO_2 resulting from the production of hydrogen at refineries and heavy oil/bitumen upgraders should be reported under subcategory 1.B.2.a.iv. Care should be taken to ensure that the feedstock for the hydrogen plant is not also reported as fuel in these cases.

Leak emissions occur in all segments of the oil and natural gas systems and consist of unintentional (i.e., not vented or flared) emissions from equipment components such as valves, connectors, open ended lines, and flanges.

Fugitive emissions from oil and natural gas systems are often difficult to quantify accurately. This is largely due to the diversity of the industry, the large number and variety of potential emission sources, the wide variations in emission-control levels and the limited availability of emission-source data. The main emission assessment issues are:

- The use of simple production-based emission factors introduces large uncertainty;
- The application of rigorous bottom-up approaches requires expert knowledge and detailed data that may be difficult and costly to obtain;
- Measurement programmes are time consuming and very costly to perform.
- Certain emissions, such as those from tanks, can be difficult to access or dangerous for direct measurement.

It is *good practice* to involve technical representatives from the industry and others with expert knowledge in the development of the inventory for the use of technology- or practice-specific Tier 1 emission factors and/or for input on Tier 2 or 3 approaches.

4.2.2.1 CHOICE OF METHOD, DECISION TREES, TIERS

There are three methodological tiers for determining fugitive emissions from oil and natural gas systems, as set out in Section 4.2.2.2. It is *good practice* to disaggregate the activities into the segments in Oil Systems and in Natural Gas Systems (see Figure 4.2.0 in Section 4.2.1, and Table 4.2.2 below), and then evaluate the emissions separately for each of these. The methodological tier applied to each segment should be commensurate with the amount of emissions and the available resources. Consequently, it may be appropriate to apply different methodological tiers to different segments and sub-segments, and possibly even include actual emission measurement or monitoring results for some larger sources. The overall approach, over time, should be one of progressive refinement to address the areas of greatest uncertainty and consequence, and to capture the impact of control measures.

Figure 4.2.1 provides a general decision tree for selecting an appropriate approach for a given segment of the natural gas industry. The decision tree is intended to be applied successively to each segment within the natural gas system (e.g., gas exploration, gas production, then gas processing, then gas transmission, then gas storage, then gas distribution, abandoned wells, post-meter emissions, and other), and then separately, to each segment within the oil system (e.g., oil production, transport systems, refineries, abandoned wells, and other).

The basic decision process is as follows:

- check if the detailed data needed to apply a Tier 3 approach are readily available, and if so, then apply a Tier 3 approach (i.e., regardless of whether the category is key and the segment is significant), otherwise, if these data are not readily available:
- check if the detailed data needed to apply a Tier 2 approach are readily available, and if so, then apply a Tier 2 approach, otherwise, if these data are not readily available:
- check to see if the category is key and the specific segment being considered is significant based on the IPCC definitions of key and significant, and if so, go back and gather the data needed to apply a Tier 3 or Tier 2 approach, otherwise, if the segment is not significant:
- apply a Tier 1 approach.

The ability to use a Tier 3 approach will depend on the availability of detailed production statistics and infrastructure data (e.g., information regarding the numbers and types of facilities and the amount and type of equipment used at each site), and it may not be possible or appropriate to apply it under all circumstances. As noted above, oil and gas systems can show significant variability across regions and over time. Compilers should make efforts to ensure that emission factors are nationally and temporally appropriate. A Tier 1 approach is the simplest method to apply but is susceptible to substantial uncertainties and may easily be in error by an order-of-magnitude or more. For this reason, it should only be used as a last resort option. Where a Tier 3 approach is used in one year and the results are used to develop Tier 2 emission factors for use in other years, the applied methodology should be reported as Tier 2 in those other years.

Where a country has estimated fugitive emissions from oil and gas systems based on a compilation of estimates reported by individual oil and gas companies, this may either be a Tier 2 or Tier 3 approach, depending on the actual approaches applied by individual companies and facilities. In both cases, care needs to be taken to ensure there is no omitting or double counting of emissions.

It is likely that most countries will estimate emissions from oil and natural gas systems using a combination of tiers across and even within segments and subsegments. Tier 1 EFs disaggregated by segment are provided in Section 4.2.2.3. The Tier 1 factors presented in this section are aggregates of venting, flaring, and leak emissions. To develop separate estimates for venting, flaring, and leak emissions, default fractions of emissions for venting, flaring, and leaks for relevant emission factors are provided in Annex 4A.2.

TABLE 4.2.2 (UPDATED) MAJOR CATEGORIES AND SUBCATEGORIES IN THE OIL AND GAS INDUSTRY	
Industry Segment	**Activities/Emission Sources[a]**
Oil Exploration 1B.2.a.i	Includes fugitive emissions associated with field activities prior to production: prospecting and or exploratory drilling, field development and well development (construction/drilling, testing, completion, any fracture stimulation).
Oil Production 1.B.2.a.ii	Onshore Production
	Offshore Production
	Crude Bitumen or Heavy Oil Upgrading to Synthetic Crude Oil (From Oil Sands or Oil Shales)
Oil Transport 1.B.2.a.iii	Marine
	Pipelines
	Tanker Trucks and Rail Cars
Oil Refining 1.B.2.a.iv	Heavy Oil
	Conventional and Synthetic Crude Oil
Refined Product Distribution 1.B.2.a.v	Gasoline
	Diesel
	Aviation Fuel
	Jet Kerosene
	Gas Oil (Intermediate Refined Products)
Other 1.B.2.a.vi	Anomalous leak events can occur across segments of Oil Systems
Abandoned Oil Wells 1.B.2.a.vii	Unplugged and plugged abandoned wells
Gas Exploration 1.B.2.b.i	Includes fugitive emissions associated with field activities prior to production: prospecting and or exploratory drilling, field development and both conventional and unconventional well development (construction/drilling, testing, completion, any fracture stimulation).
Gas Production 1.B.2.b.ii	Onshore gas production
	Offshore gas production
	Gathering and boosting stations (with multiple emission sources on site, such as compressors, pneumatic controllers and tanks) and gathering pipelines

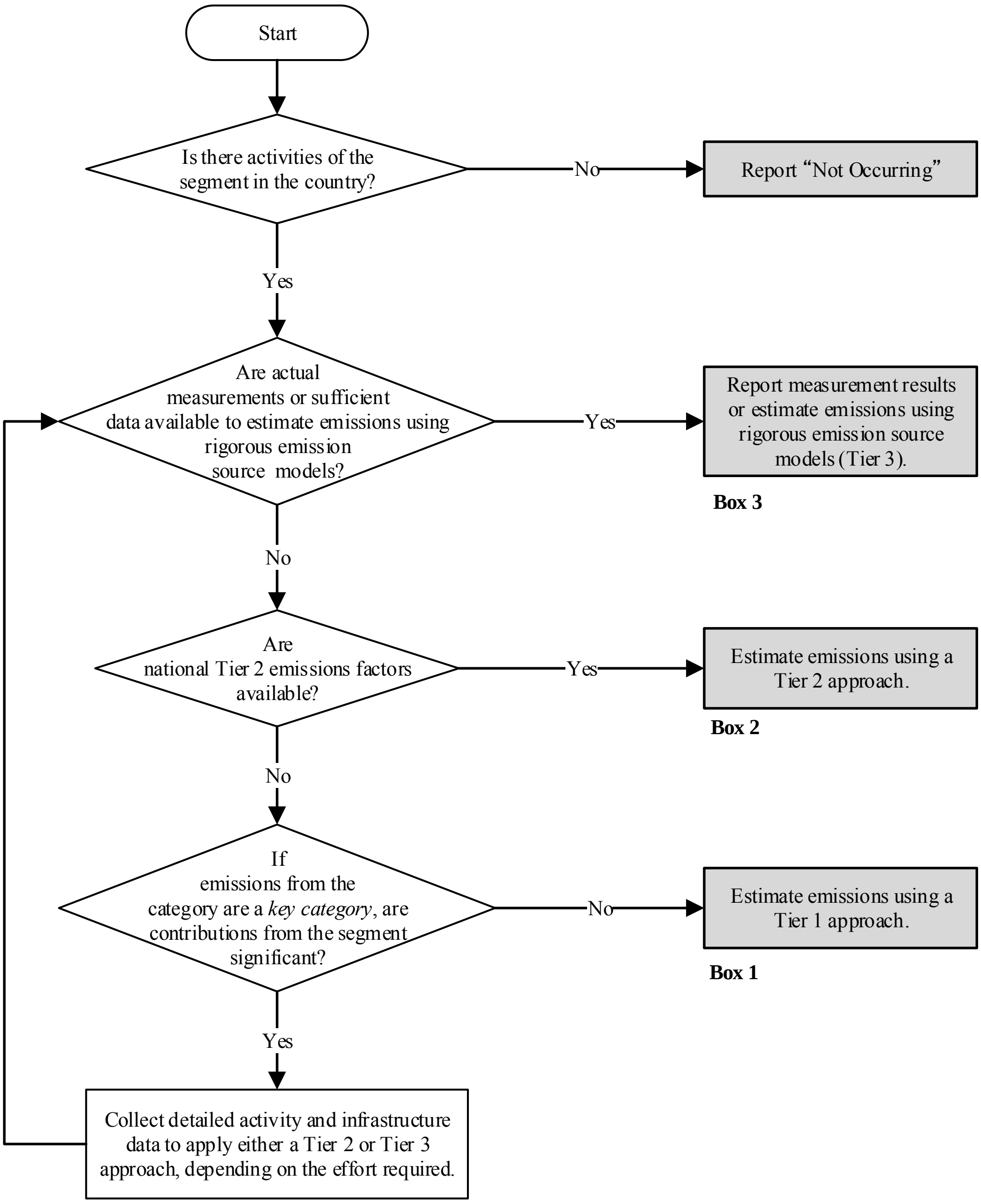
TABLE 4.2.2 (UPDATED) (CONTINUED)
MAJOR CATEGORIES AND SUBCATEGORIES IN THE OIL AND GAS INDUSTRY

Industry Segment	Activities/Emission Sources[a]
Gas Processing 1.B.2.b.iii	Gas Processing Plants without Acid Gas Removal
	Sour Gas or Acid Gas Removal Plants
Gas Transmission & Storage 1.B.2.b.iv	Transmission pipeline Systems, compressor stations
	Storage Facilities
	Liquefied Natural Gas System import stations, export stations, storage stations, and transport
Gas Distribution 1.B.2.b.v	Pipelines
Post-Meter Emissions 1.B.2.b.vi	Metering and regulating stations, consumer appliances
Other 1.B.2.b.vii	Anomalous leak events can occur across natural gas systems. Examples of such events include leakage of storage wells (such as the 2015-2016 Aliso Canyon leak event[b]), emergency pressure releases, and unintentional gas spills (e.g. after prospecting).
Abandoned Gas Wells 1.B.2.b.viii	Unplugged and plugged abandoned wells

[a] See Annex 4A.3 Definition of terminologies used in Section 4.2.

[b] For more information on the Aliso Canyon leak event, please see (California Air Resources Board 2016)

Figure 4.2.1 (Updated) Decision tree for oil and natural gas systems



* For oil production segment: is it possible to perform alternative mass balance approach

4.2.2.2 CHOICE OF METHOD

The three methodological tiers for estimating fugitive emissions from oil and natural gas systems are described below.

TIER 1

Tier 1 comprises the application of appropriate default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subsegment of a country's oil and natural gas industry and should only be used as specified in the decision trees. The application of a Tier1 approach is illustrated with Equations 4.2.1 and 4.2.2 presented below. More detailed equations and guidance can be found in Section 4.2.2.3.

EQUATION 4.2.1
TIER 1: ESTIMATING FUGITIVE EMISSIONS FROM AN INDUSTRY SEGMENT

$$E_{gas,\,industry\ segment} = A_{industry\ segment} \bullet EF_{gas,\,industry\ segment}$$

EQUATION 4.2.2
TIER 1: TOTAL FUGITIVE EMISSIONS FROM INDUSTRY SEGMENTS

$$E_{gas} = \sum_{industry\ segments} E_{gas,industry\ segment}$$

Where:

$E_{gas,industry\ segement}$ = Annual emissions of CO_2, CH_4, or N_2O (tonnes)

$EF_{gas,industry\ segement}$ = emission factor for CO_2, CH_4, or N_2O (tonnes/unit of activity)

$A_{industry\ segement}$ = activity value (units of activity)

The industry segments to be considered are listed in Table 4.2.2. Not all segments will necessarily apply to all countries. For example, a country that only imports natural gas and does not produce any will probably only have gas transmission and distribution emissions. The available Tier 1 default emission factors are presented in Table 4.2.4 through 4.2.4k in Section 4.2.2.3. Several options for activity data are available for many of the factors. For each segment, at least one factor option has been related to throughput, because production, imports and exports, and consumption are the only national oil and gas statistics that are consistently available. Throughput emission factors are applicable to throughput at standard conditions of 15°C and 101.325 kPa. For more information on standard temperature and pressure conditions, and conversions from different conditions, see Annex 4A.1.

In addition, for many segments, technology- or practice-specific emission factors are available. Information on the appropriate use of each factor is included in Section 4.2.2.3 for each technology-specific factor.

Compilers are to assess which Tier 1 factors are most appropriate and should consider other sources or a more disaggregated EF (by emission type; see Annex 4A.2) if the emission factors presented here are expected to vary significantly from national circumstances.

Fugitive greenhouse gas emissions from oil and gas related CO_2 capture and injection activities (e.g., acid gas injection and EOR projects involving CO_2 floods) will normally be small compared to the amount of CO_2 being injected (e.g., less than 1 percent of the injection volumes). At the Tier 1 or 2 methodology levels they are indistinguishable from fugitive greenhouse gas emissions by the associated oil and gas activities. The emission contributions from CO_2 capture and injection were included in the original data from which the presented Tier 1 factors were developed (i.e., through the inclusion of acid gas injection and EOR activities, along with conventional oil and gas activities, with consideration of CO_2 concentrations in the leaked, vented and flared natural gases, vapours and acid gases). Losses from CO_2 capture should be accounted for in the industry where capture occurs, while losses from, transport, injection and storage activities are assessed separately in Chapter 5.

TIER 2

Tier 2 consists of using Tier 1 equations (4.2.1 and 4.2.2) with country-specific, instead of default, emission factors. It should be applied to significant segments in *key categories* where the use of a Tier 3 approach is not practicable. The country-specific values may be developed from studies and measurement programmes, or be derived by initially applying a Tier 3 approach and then back-calculating Tier 2 emission factors using Equations 4.2.1 and 4.2.2. For example, some countries have been applying Tier 3 approaches for particular years and have then used these results to develop Tier 2 factors for use in subsequent years until the next Tier 3 assessment is performed. In general, all emission factors (including Tier 1 and Tier 2 values) should be periodically re-affirmed or updated. The frequency at which such updates are performed shall be commensurate with the rates at which new technologies, practices, standards and other relevant factors (e.g., changes in the types of oil and gas activities, aging of the fields and facilities, etc.) are penetrating the industry. New data shall be assessed to determine whether the data are representing different practices, equipment, or conditions, or if it is an additional data point to be included in the emission factor applied across all time series years. A survey of operations for information on practices over time could be used to make such an assessment. If new emission factors developed in this manner account for real changes within the industry, they should not be applied backwards through the time series.

An alternative Tier 2 approach that may be applied to estimate the amount of venting and flaring emissions from the production segment of oil systems consists of performing a mass balance using country-specific production volumes, gas-to-oil ratios (GORs), gas compositions and information regarding the level of gas conservation. This approach may be applied using Equations 4.2.3 to 4.2.8 below and is appropriate where reliable venting and flaring values are unavailable but representative GOR data can be obtained and venting and flaring emissions are expected to be the dominant sources of fugitive emissions (i.e., most of the associated gas production is not being captured/conserved or utilized). Under these circumstances, the alternative Tier 2 approach may also be used to estimate fugitive greenhouse gas emissions from EOR activities provided representative associated gas and vapour analyses are available and contributions due to fugitive emissions from the CO_2 transport and injection systems are small in comparison (as would normally be expected). Where the alternative Tier 2 approach is applied, any reported venting or flaring data that may be available for the target sources should not also be accounted for as this would result in double counting. However, it is *good practice* to compare the estimated gas vented and flared volumes determined using the GOR data to the available reported vented and flared data to identify and resolve any potential anomalies (i.e., the calculated volumes should be comparable to the available reported data, or greater if these latter data are believed to be incomplete). In the case that Tier 2 vented and flared data are applied for certain segments, leak emissions should be calculated separately using other data, for example, disaggregated Tier 1 emissions factors (see Annex 4A.2)

Table 4.2.3 shows examples of typical GOR values for oil wells from selected locations. Actual GOR values may vary from 0 to very high values depending on the local geology, state of the producing reservoir and the rate of production. Notwithstanding this, average GOR values for large numbers of oil wells tend to be more predictable. A review of limited data for a number of countries and regions indicates that average GOR values for conventional oil production would usually be in the range of about 100 to 350 m^3/m^3, depending on the location. When country-specific GORs are used, care should be taken to ensure that GOR measurements are performed with enough frequency to ensure representative results.

TABLE 4.2.3
TYPICAL RANGES OF GAS-TO-OIL RATIOS FOR DIFFERENT TYPES OF PRODUCTION

Type of Crude Oil Production	Location	Typical GOR Values (m^3/m^3)	
		Range[6]	Average
Conventional Oil	Alaska (Prudhoe Bay)	142 to 6,234[2, 3]	NA
	Canada	0 to 2,000+ [1, 2]	Not Available (NA)
	Qatar (Onshore, 1 Oil Field)	167 to 184[4]	173
	Qatar (Offshore, 3 Oil Fields)	316 to 386[4]	333
Primary Heavy Oil	Canada	0 to 325+ [1, 5]	NA
Thermal Heavy Oil	Canada	0 to 90[1]	NA
Crude Bitumen	Canada	0 to 20[1]	NA

[1] Source: Based on unpublished data for a selection of wells in Canada.

[2] Appreciably higher GOR values may occur, but these wells are normally either classified as gas wells or there is a significant gas cap present and the gas would normally be reinjected until all the recoverable oil had been produced.

[3] Source: Mohaghegh, S.D., L.A. Hutchins and C.D. Sisk. 2002. Prudhoe Bay Oil Production Optimization: Using Virtual intelligence Techniques, Stage One: Neural Model Building. Presented at the SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, 29 September–2 October 2002.

[4] Source: Corporate HSE, Qatar Petroleum, Qatar-Doha 2004.

[5] Values as high as 7,160 m^3/m^3 have been observed for some wells where there is a significant gas cap present. Gas reinjection is not done in these applications. The gas is conserved, vented or flared.

[6] Referenced at standard conditions of 15°C and 101.325 kPa.

To apply a mass balance method in the alternative Tier 2 approach, it is necessary to consider the fate of all of the produced gas and vapour. This is done, in part, through the application of a conservation efficiency (CE) factor which expresses the amount of the produced gas and vapour that is captured and used for fuel, produced into gas gathering systems or re-injected. A CE value of 1.0 means all gas is conserved, utilized or re-injected and a value of 0 means all of the gas is either vented or flared. Values may be expected to range from about 0.1 to 0.95. The lower limit applies where only process fuel is drawn from the produced gas and the rest is vented or flared. A value of 0.95 reflects circumstances where there is, generally, good access to gas gathering systems and local regulations emphasize vent and flare gas reduction.

EQUATION 4.2.3
ALTERNATIVE TIER 2 APPROACH (EMISSIONS DUE TO VENTING)

$$E_{gas,oil\ prod,\ venting} = GOR \bullet Q_{OIL} \bullet (1-CE) \bullet (1-X_{Flared}) \bullet M_{gas} \bullet y_{gas} \bullet 42.3 \times 10^{-6}$$

EQUATION 4.2.4
ALTERNATIVE TIER 2 APPROACH (CH_4 EMISSIONS DUE TO FLARING)

$$E_{CH4,oil\ prod,flaring} = GOR \bullet Q_{OIL} \bullet (1-CE) \bullet X_{Flared} \bullet (1-FE) \bullet M_{CH4} \bullet y_{CH4} \bullet 42.3 \times 10^{-6}$$

EQUATION 4.2.5
ALTERNATIVE TIER 2 APPROACH (CO_2 EMISSIONS DUE TO FLARING)

$$E_{CO2,oilprod,flaring} = GOR \bullet Q_{OIL} \bullet (1 - CE) \bullet X_{Flared} \bullet M_{CO2} \bullet \left[y_{CO2} + (Nc_{CH4} \bullet y_{CH4} + Nc_{NMVOC} \bullet y_{NMVOC})(1 - X_{Soot})\right] \bullet 42.3\text{x}10^{-6}$$

EQUATION 4.2.6
CH_4 EMISSIONS FROM FLARING AND VENTING

$$E_{CH4,oil\ prod} = E_{CH4,oil\ prod,venting} + E_{CH4,oil\ prod,flaring}$$

EQUATION 4.2.7
CO_2 EMISSIONS FROM VENTING AND FLARING

$$E_{CO2,oil\ prod} = E_{CO2,oil\ prod,venting} + E_{CO2,oil\ prod,flaring}$$

EQUATION 4.2.8
N_2O EMISSIONS FROM FLARING

$$E_{N2O,oil\ prod,flaring} = GOR \bullet Q_{OIL}(1 - CE)X_{Flared}EF_{N2O}$$

Where:

$E_{i,\ oil\ prod,\ venting}$ = Direct amount (Gg/y) of GHG gas *i* emitted due to venting at oil production facilities

$E_{i,\ oil\ prod,\ flaring}$ = Direct amount (Gg/y) of GHG gas *i* emitted due to flaring at oil production facilities

GOR = Average gas-to-oil ratio (m^3/m^3) referenced at 15ºC and 101.325 kPa

Q_{OIL} = Total annual oil production ($10^3\ m^3/y$)

M_{gas}= Molecular weight of the gas of interest (e.g., 16.043 for CH_4 and 44.011 for CO_2)

$N_{C,i}$ = Number of moles of carbon per mole of compound *i* (i.e., 1 for CH_4, 2 for C_2H_6, 3 for C_3H_8, 1 for CO_2, 2.1 to 2.7 for the NMVOC fraction in natural gas and 4.6 for the NMVOC fraction of crude oil vapours)

y_i = Mol or volume fraction of the associated gas that is composed of substance i (i.e., CH_4, CO_2 or NMVOC)

CE = Gas conservation efficiency factor

X_{Flared} = Fraction of the waste gas that is flared rather than vented. With the exception of primary heavy oil wells, usually most of the waste gas is flared.

FE = flaring destruction efficiency (i.e., fraction of the gas that leaves the flare partially or fully burned). Typically, a value of 0.995 is assumed for flares at refineries and a value 0.98 is assumed for those used at production and processing facilities.

$\mathrm{X_{soot}}$ = fraction of the non-CO_2 carbon in the input waste gas stream that is converted to soot or particulate matter during flaring. In the absence of any applicable data this value may be assumed to be 0 as a conservative approximation.

$\mathrm{EF_{N2O}}$ = emission factor for N_2O from flaring ($Gg/10^3\ m^3$ of associated gas flared). Refer to the IPCC emission factor database (EFDB), manufacturer's data or other appropriate sources for the value of this factor.

$42.3\text{x}10^{-6}$ = is the number of kmol per m^3 of gas referenced at 101.325 kPa and 15ºC (i.e. $42.3\text{x}10^{-3}$ kmol/m^3) times a unit conversion factor of 10^{-3} Gg/Mg which brings the results of each applicable equation to units of Gg/y.

The values of $E_{CH4,\ oil\ prod,\ venting}$ and $E_{CO2,\ oil\ prod,\ venting}$ in Equations 4.2.6 and 4.2.7 are estimated using Equation 4.2.3.

It should be noted that Equation 4.2.5 accounts for emissions of CO_2 using a similar approach to what is done for fuel combustion in Section 1.3 of the Introduction chapter of the Energy Volume. The term yCO_2 in this equation effectively accounts for the amount of raw (or formation CO_2) present in the waste gas being flared. The terms $NcCH_4$ ● yCH_4 and NcNMVOC ● yNMVOC in Equation 4.2.5 account for the amount of CO_2 produced per unit of CH_4 and NMVOC oxidized.

TIER 3

Tier 3 comprises the application of a rigorous bottom-up assessment by primary type of source (e.g., venting, flaring, equipment leaks, evaporation losses and accidental releases) at the individual facility level with appropriate accounting of contributions from temporary and minor field or well-site installations. It should be used for *key categories* where the necessary activity and infrastructure data are readily available or are reasonable to obtain. Tier 3 should also be used to estimate emissions from surface facilities where EOR, EGR and ECBM are being used in association with CCS. Approaches that estimate emissions at a less disaggregated level than this (e.g., relate emissions to the number of facilities or the amount of throughput) are deemed to be equivalent to a Tier 1 approach if the applied factors are taken from the general literature, or a Tier 2 approach if they are country-specific values.

The key types of data that would be utilized in a Tier 3 assessment would include the following:

- Facility inventory, including an assessment of the type and amount of equipment or process units at each facility, and major emission controls (e.g., vapour recovery, waste gas incineration, etc.).
- Inventory of wells and minor field installations (e.g., field dehydrators, line heaters, well site metering, etc.).
- Country-specific flare, vent and process gas analyses for each subcategory.
- Facility-level acid gas production, analyses and disposition data.
- Reported atmospheric releases due to well blow-outs and pipeline ruptures.
- Country-specific emission factors for fugitive equipment leaks, unaccounted/unreported venting and flaring, flashing losses at production facilities, evaporation losses, etc.
- The amount and composition of acid gas that is injected into secure underground formations for disposal.

Oil and gas projects that involve CO_2 injection as a means of enhancing production (e.g., EOR, EGR and ECBM projects) or as a disposal option (e.g., acid gas injection at sour gas processing plants) should distinguish between the CO_2 capture, transport, injection and sequestering part of the project, and the oil and gas production portion of the project. The net amount of CO_2 sequestered and the fugitive emissions from the CO_2 systems should be determined based on the criteria specified in Chapter 5 for CO_2 capture and storage. Any fugitive emissions from the oil and gas systems in these projects should be assessed based on the guidance provided here in Chapter 4 and will exhibit increasing concentrations of CO_2 over time in the emitted natural gas and hydrocarbon vapours. Accordingly, the applied emission factors may need to be periodically updated to account for this fact. Also, care should be taken to ensure that proper total accounting of all CO_2 between the two portions of the project occurs.

4.2.2.3 CHOICE OF EMISSION FACTOR

Oil and gas technologies and practices and therefore, emissions, can vary greatly from country to country and over time. Data availability may also vary between countries and change over time. Tier 1 emission factors are listed in the tables below by segment. Tier 2 and 3 emission factors are also discussed below. It is likely that many countries will use a combination of tiers to calculate emissions across petroleum and natural gas systems.

TIER 1

Tier 1 default emission factors for each segment of oil and natural gas systems are presented in tables below. Each factor represents emissions per year.

Several options for activity data are available for many of the factors. For each segment, at least one factor option has been related to throughput, because production, imports and exports, and consumption are often the only national oil and gas statistics that are consistently available in many countries. However, fugitive emissions may be more dependent on other factors. An improved basis for estimating emissions for many sources might use other activity data (e.g. length of pipeline). The tables in Section 4.2.2.3 provide options for emission factors to be applied to other activity data where possible, and where appropriate. In addition, for many segments, technology- or practice-specific emission factors are available. Information on the appropriate use of each factor is included for each technology-specific factor. Compilers are to assess which Tier 1 factors are most appropriate and should consider other sources or a more disaggregated EF (see Annex 4A.2) if the emission factors presented here are expected to vary significantly from national circumstances.

The Tier 1 factors presented in this section are aggregates of venting, flaring, and leak emissions. To develop separate estimates for venting, flaring, and leak emissions, default fractions of emissions in each category for relevant emission factors are provided in Annex 4A.2.

It should be noted that the default EFs listed in Tables 4.2.4 to 4.2.4k are sensitive to temperature and pressure. Activity data must be consistent with the EFs standard conditions. For more information on conversions to standard temperature and pressure, please see Annex 4A.1.

The factors in Tables 4.2.4 to 4.2.4k are derived using detailed emission inventory results from the United States, Canada, Australia, Germany, and other countries, and, where possible, have been updated from the values previously presented in the IPCC Guidelines for National Greenhouse Gas Inventories (2006) document to reflect the results of more current and refined emissions inventories. In many cases, technology- and practice-specific emission factors are presented, so that an inventory compiler may select factors that best represent industry practices in the country. While the emission factor options are meant to cover technologies and practices that are common in the oil and gas industries, technologies and practices can vary significantly. In addition, the accuracy of factors is dependent on the uncertainty of underlying data. A country should periodically assess changes in technologies and practices, and changes in available emissions data, and consider updating estimates using at least a Tier 2 approach, per *good practice*.

Oil Systems

1 B 2 a i Exploration.

This segment includes fugitive emissions (including equipment leaks, venting and flaring) from all field activities prior to production (e.g. prospecting and exploratory well drilling, well/drill stem testing and completions).[5] In this segment, factors are not disaggregated to drilling, testing and servicing operation; EFs are applied to the whole segment.

In Table 4.2.4, several options for onshore exploration emission factors inclusive of venting, flaring, and leaks are presented. Each technology/practice-specific emission factor is presented in units of tonne per oil well drilled, tonne per active oil well, and in tonnes per thousand cubic meter oil produced. The count of wells drilled is thought to best reflect emissions from exploration and if available should be applied. However, the inventory compiler should assess which activity data are available and which activity data basis best reflects emissions in that segment for that country.

Emission factors are available for both onshore unconventional and onshore conventional oil exploration. Offshore exploration emissions data are unavailable, and these emissions are thought to be negligible; therefore, emission factors are not included for offshore exploration. Here, unconventional oil exploration refers to exploration where hydraulic fracturing well completion practices are used, and conventional oil exploration refers to exploration where hydraulic fracturing well completion practices are not used.

The extent of any hydraulic fracturing activities in the country should be assessed. Unconventional completions (i.e., conducted with hydraulic fracturing) have a different emissions profile than conventional completions (i.e., conducted without hydraulic fracturing). This is reflected in the emission factors below. Where possible, the compiler should separate national activity data into conventional and unconventional categories and apply the relevant emission factors. If only total oil wells or total oil production data are available, the compiler should develop an estimate of the annual split between conventional and unconventional wells or conventional and unconventional production in the country to develop the activity data. Unconventional factors are to be applied to the unconventional activity data basis. Where wells drilled are completed with hydraulic fracturing and flaring and gas recovery is not practiced, or where the extent of flaring or recovery practices is unknown, the first set of factors ("Unconventional without flaring or recovery") should be used and applied to the relevant activity data (i.e. unconventional wells drilled, total unconventional well population, or unconventional production). Where wells drilled are completed with hydraulic fracturing and flaring and gas recovery is used, the fraction of the relevant activity data that uses flaring and/or gas recovery should be determined. The second set of factors ("Unconventional with flaring") is used for that fraction, while the first set of factors is applied to the wells or production that are not using flaring or recovery. Conventional factors ("Conventional") are to be applied to the conventional activity data basis. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series.

Factors presented are inclusive of venting, flaring, and leak emissions. For cases where country-specific data are available for a subcomponent of the factor (e.g. venting and flaring emissions), disaggregated Tier 1 EF that could

[5] Refracturing and redrilling emissions are to be included in 1.B.2.a.ii (Production and Upgrading).

be applied to estimate the remaining emission types are available—see Annex 4A.2 for information (including examples) on how to calculate disaggregated emissions.

Definitions for oil wells versus gas wells can vary from country to country and organization to organization. The Tier 1 EFs in the table below were developed from emissions occurring in U.S. basins identified as having predominantly oil production. Emission factors were developed using data on exploration emissions (drilling, testing, and completions) for wells with a gas oil ratio of </= 17,000 cubic meters gas to cubic meters oil. If national criteria defines oil and gas wells, follow the national criteria or national documentation to make the distinction. What is most important is that all emissions are transparently allocated to either oil or gas systems, without omission.

For each sub-segment listed in Table 4.2.4 below that is occurring in the country, compilers must calculate emissions, and sum them according to Equation 4.2.9. It is recognized that not all countries will have all sub-segments (i.e. technologies or practices) occurring. Factors listed in Table 4.2.4 apply to onshore exploration. Emissions data are unavailable for offshore exploration.

EQUATION 4.2.9 (NEW)
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM EXPLORATION

$$E_{exploration} = A_{unconventional\ oil\ without\ flaring\ or\ recovery} \bullet EF_{unconventional\ oil\ without\ flaring\ or\ recovery} + A_{unconventional\ oil\ with\ flaring\ or\ recovery} \bullet EF_{unconventional\ oil\ with\ flaring\ or\ recovery} + A_{conventional\ oil} \bullet EF_{conventional\ oil}$$

Where:

$E_{exploration}$ = Total amount of GHG gas emitted due to all relevant oil exploration activities

$A_{unconventional\ oil\ without\ flaring\ or\ recovery}$ = Activity data on exploration of unconventional oil without flaring or recover

$EF_{unconventional\ oil\ without\ flaring\ or\ recovery}$ = Emission factor for exploration of unconventional oil without flaring or recovery

$A_{unconventional\ oil\ with\ flaring\ or\ recovery}$ = Activity data on exploration of unconventional oil with flaring or recovery

$EF_{unconventional\ oil\ with\ flaring\ or\ recovery}$ = Emission factor for exploration of unconventional oil with flaring or recovery

$A_{conventional\ oil}$ = Activity data on exploration of conventional oil

$EF_{conventional\ oil}$ = Emission factor for exploration of conventional oil

TABLE 4.2.4 (UPDATED)
TIER 1 EMISSION FACTORS FOR OIL EXPLORATION, 1.B.2.A.I

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Oil exploration	Onshore unconven-tional without flaring or recovery[a, d]	All	6.63	-30% to +30%	14.35	-30% to +30%	0.99	-12.5 to +800%	NA	NA	Tonnes/unconventional onshore oil wells drilled in a year, without flaring or recovery
			0.46	-30% to +30%	0.97	-30% to +30%	0.07	-12.5 to +800%	NA	NA	Tonnes/total unconventional onshore oil well population where exploration occurs without flaring or recovery
			1.64	-30% to +30%	3.49	-30% to +30%	0.25	-12.5 to +800%	NA	NA	Tonnes/thousand cubic meters onshore unconventional oil production where exploration occurs without flaring or recovery
Oil exploration	Onshore unconven-tional with flaring or recovery[b, d]	All	0.81	-30% to +30%	11.25	-30% to +30%	0.12	-12.5 to +800%	8.2E-05	-10 to +1000%	Tonnes/unconventional onshore oil wells drilled in a year, with flaring or recovery
			0.07	-30% to +30%	1.03	-30% to +30%	0.01	-12.5 to +800%	7.5E-06	-10 to +1000%	Tonnes/total unconventional onshore oil well population where exploration occurs with flaring or recovery
			0.06	-30% to +30%	0.86	-30% to +30%	0.01	-12.5 to +800%	6.3E-06	-10 to +1000%	Tonnes/thousand cubic meters onshore unconventional oil production where exploration occurs with flaring or recovery
Oil exploration	Onshore Conventional[c]	All	0.53	-30% to +30%	12.44	-30% to +30%	0.08	-12.5 to +800%	9.0E-05	-10 to +1000%	Tonnes/onshore conventional oil wells drilled in a year
			0.01	-30% to +30%	0.22	-30% to +30%	1.4E-03	-12.5 to +800%	1.6E-06	-10 to +1000%	Tonnes/total conventional onshore oil well population
			0.02	-30% to +30%	0.44	-30% to +30%	2.8E-03	-12.5 to +800%	3.2E-06	-10 to +1000%	Tonnes/thousand cubic meters onshore conventional oil production

TABLE 4.2.4 (UPDATED) (CONTINUED)
TIER 1 EMISSION FACTORS FOR OIL EXPLORATION, 1.B.2.A.I

NA – Not Applicable

a. Emission factors for CH_4 and CO_2 developed from memo on production segment method updates for unconventional oil well completions, (Radian International LLC 1999) for drilling emissions, and U.S. Greenhouse Gas Reporting Program (GHGRP) (United States Environmental Protection Agency (EPA) 2017) data on well testing, as applied in the 2018 U.S. GHG Inventory (United States Environmental Protection Agency (EPA) 2018a); factor is an average of 2006-2010 calculated implied emission factors for emissions from well drilling, well testing, and from well completions with hydraulic fracturing that do not flare or use gas capture. The time period of 2006-2010 was selected as it represents a time when hydraulic fracturing is occurring, but before state or federal regulations were in place to control gas emissions. NMVOC values were developed from *IPCC 2006* GL by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table.

b. Emission factors for CH_4 and CO_2 developed from (United States Environmental Protection Agency (EPA) 2016a) for unconventional oil well completions, from (Radian International LLC 1999) for drilling emissions, and GHGRP (United States Environmental Protection Agency (EPA) 2017) data on well testing, as applied in the 2018 U.S. GHG Inventory. Factor is the average of 2012-2016 calculated implied emission factors for emissions from well drilling, well testing, and from well completions with hydraulic fracturing that flare or use gas capture. The time period of 2013-2016 was selected as it represents a time when hydraulic fracturing is occurring and state or federal regulations were in place to control gas emissions. NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from *IPCC 2006 GL* by calculating a ratio of N_2O to CO_2 from *IPCC 2006*, which was then applied to corresponding CO_2 values in this table.

c. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996) for conventional oil well completions, GHGRP (United States Environmental Protection Agency (EPA) 2017) for well testing, and (Radian International LLC 1999) for drilling emissions, as applied in the 2018 U.S. GHG Inventory. Factor is the average of 2006-2016 calculated implied emission factors for emissions from well drilling, well testing and from conventional completions. The time period of 2006-2016 was selected to cover the time frame of the other exploration factors. NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from *IPCC 2006 GL* by calculating a ratio of N_2O to CO_2 from *IPCC 2006*, which was then applied to corresponding CO_2 values in this table.

d. Unconventional oil exploration refers to exploration that includes well completions with hydraulic fracturing. Conventional oil exploration emission factors should be applied where hydraulic fracturing well completion practices are not used.

1 B 2 a ii Production and Upgrading

This segment includes fugitive emissions from oil production (including leaks, venting, and flaring) from the oil wellhead or at the oil sands or shale oil mine through to the start of the oil transmission system. On-site crude oil processing (i.e. removing water and gases contained in crude oil) is also included in this segment. Emissions arise from the wells themselves (e.g., as wellhead leaks and from well workovers and refractures), and well-site equipment such as pneumatic controllers, dehydrators and separators. This includes fugitive emissions related to oil sands or shale oil mining, transport of untreated production (i.e. well effluent, emulsion, oil shale and oil sands) to treating or extraction facilities, activities at extraction and upgrading facilities, associated gas re-injection systems and produced water disposal systems. Fugitive emissions from upgraders are grouped with those from production rather than those from refining since the major product from upgraders (i.e. synthetic crude oil) requires further processing at refineries. Upgraders are often integrated with extraction facilities and may also be integrated with refineries, co-generation plants or other industrial facilities, making their relative contributions difficult to establish.

Table 4.2.4a presents factors for onshore oil production, and offshore oil production.

Countries with onshore oil production should apply a factor for onshore production to the relevant activity data for onshore production. Factors for onshore production (other than for oil sands) are presented both in units of tonne per active oil well, and in tonnes per thousand cubic meter oil produced. The count of wells is thought to best reflect emissions from oil production, and if complete and accurate well count data are available, they should be applied. However, the inventory compiler should assess which activity data are available and which activity data basis best reflects emissions in that segment for that country. The types of technologies and practices in use in the country should be assessed, including the extent of associated gas venting and flaring, and use of controls at tanks. Where this information is unknown, or where more than 5% of associated gas is vented, or more than 30% of tank throughput is uncontrolled (e.g. without flaring or VRUs), the first set of emission factors for oil production ("Most activities occurring with higher-emitting technologies and practices") should be used. Where lower-emitting technologies are used extensively (e.g. associated gas is used or flared instead of vented, most tanks are controlled), the second set of emission factors ("Most activities occurring with lower-emitting technologies and practices") for oil production should be used. The emission factors for onshore production were developed from data sets that included a mix of production from wells in conventional formations and wells in unconventional formations and are considered to be applicable to both. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series.

Countries with offshore oil production should apply a factor for offshore oil production. If no data are available to estimate the share of oil production that occurs offshore, the EF for onshore production should be applied to the total quantity of oil production.

Production from oil sands is treated separately and should use emission factors for "Oil Sands Mining and Ore Processing" and "Oil Sands Upgrading" to calculation emissions for that subset of oil production.

Oil sands are a type of unconventional petroleum deposit made of up a mixture of sand, clay, and water, saturated with a highly viscous form of petroleum called crude bitumen. Crude bitumen is an extra-heavy oil with an API gravity below 10°API. In its natural state, it is not usually recoverable at commercial rates through a well because it is too thick to flow. There are two methods that are used to recover crude bitumen, depending on the depth of the deposit. Bitumen that occurs near the surface can be recovered by open-pit mining. In this method, overburden is removed, oil sands ore is mined, and bitumen is recovered from the mined material in large facilities using hot water and solvents. When the resource is located too deep to make surface mining economical, in situ extraction methods are utilized. In situ extraction takes place both through primary extraction methods, similar to conventional crude oil, and enhanced extraction. The two main methods of enhanced recovery are cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). Both methods use steam to heat the reservoir allowing the bitumen to flow to a vertical or horizontal wellbore. Due to the large quantities of both hot water and steam needed to extract the bitumen, co-generation plants are often co-located with the extraction facilities.

Once the bitumen is produced using surface mining or in situ methods, it can be upgraded to synthetic crude oil (SCO) or lighter hydrocarbon products at an upgrader and then transported to a refinery for further processing. Upgraders improve the quality of the crude bitumen by adding hydrogen, removing carbon, or both. During the upgrading process, most of the sulphur and other impurities are removed. The produced bitumen can also be mixed with a less viscous material (referred to as diluent), such as SCO or condensate, allowing the mixture to flow through a pipeline.

Fugitive emissions from in situ extraction include leaks, venting and flaring that occur at the well pad through to the start of the oil transmission system. Open pit mining extraction of crude bitumen also includes fugitive emissions from leaks, venting and flaring. Additional methane present in the oil sands ore is released during mining, mine dewatering, and ore transport, crushing and handling activities. Waste tailings are created during the extraction process consisting of unrecovered solvent, bitumen, water, sand, clay and other impurities. Fugitive emissions from tailings ponds occur as microbial and bacterial degradation of hydrocarbons and vegetation present at the bottom of the ponds produces methane gas. The upgrading process produces fugitive emissions of leaks, venting and flaring, including CO_2 venting from sulphur recovery operations and the hydrogen production process.

Factors presented are inclusive of venting, flaring, and leak emissions. For cases where country-specific data are available for a subcomponent of the factor (e.g. venting and flaring emissions), disaggregated Tier 1 EF that could be applied to estimate the remaining emission types are available—see Annex 4A.2 for information (including examples) on how to calculate disaggregated emissions.

Definitions for oil wells versus gas wells can vary from country to country and organization to organization. The onshore production (other than oil sands) Tier 1 EFs in the table below were developed from emissions occurring in U.S. basins identified as having predominantly oil production. Emission factors were developed using data on production emissions for wells with a gas oil ratio of </= 17,000 cubic meters gas to cubic meters oil. If national criteria defines oil and gas wells, follow the national criteria or national documentation to make the distinction. What is most important is that all emissions are transparently allocated to either oil or gas systems, without omission.

For each segment/sub-segment listed in Table 4.2.4a below that is occurring in the country, compilers must calculate emissions, and sum them according to Equation 4.2.10. It is recognized that not all countries will have all segments and sub-segments occurring.

EQUATION 4.2.10 (NEW)
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM OIL PRODUCTION AND UPGRADING

$$E_{oil\ production} = A_{onshore\ oil\ production} \bullet EF_{onshore\ oil\ production} + A_{offshore\ oil\ production} \bullet EF_{offshore\ oil\ production} + A_{oil\ sands\ processing} \bullet EF_{oil\ sands\ processing} + A_{oil\ sands\ upgrading} \bullet EF_{oil\ sands\ upgrading}$$

Where:

$E_{oil\ production}$ = Total amount of GHG gas emitted due to all relevant oil production activities

$A_{onshore\ oil\ production}$ = Volume of onshore oil produced or number of onshore active wells

$EF_{onshore\ oil\ production}$ = Emission factor for onshore oil production

$A_{offshore\ oil\ production}$ = Volume of offshore oil produced

$EF_{offshore\ oil\ production}$ = Emission factor for offshore oil production

$A_{oil\ sands\ processing}$ = Volume of crude bitumen produced from surface mining

$EF_{oil\ sands\ processing}$ = Emission factor for processing of oil sands

$A_{oil\ sands\ upgrading}$ = Volume of synthetic crude oil produced

$EF_{oil\ sands\ upgrading}$ = Emission factor for upgrading of oil sands

TABLE 4.2.4A (NEW)
TIER 1 EMISSION FACTORS FOR OIL PRODUCTION, 1.B.2.A.II

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Oil Production	Onshore: Most activities occurring with higher-emitting technologies and practices[a]	All	3.43	±30%	12.40	±30%	1.48	-100% to +800%	1.9E-04	-10% to +1000%	Tonnes/thousand cubic meters onshore oil production
			2.35	±30%	8.47	±30%	1.01	-100% to +800%	1.3E-04	-10% to +1000%	Tonnes per active onshore oil well
Oil Production	Onshore: Most activities occurring with lower-emitting technologies and practices[b]	All	2.91	±30%	44.99	±30%	1.25	-100% to +800%	6.7E-04	-10% to+1000 %	Tonnes/thousand cubic meters onshore oil production
			2.19	±30%	33.83	±30%	0.94	-100% to +800%	5.1E-04	-10% to +1000%	Tonnes per active onshore oil well
Oil Production	Onshore: Oil Sands Mining and Ore Processing[c]	All	0.74	±30%	7.56	±25%	0.65	-30% to +95%	1.1E-05	-30% to +520%	Tonnes/thousand cubic meters crude bitumen production from surface mining
Oil Production	Onshore: Oil Sands Upgrading[d]	All	0.13	-35% to +120%	90.73	±15%	0.07	-60% to +75%	2.8E-05	-25% to +315%	Tonnes/thousand cubic meters synthetic crude oil production
Oil Production	Offshore[e]	All	2.46	±30%	4.08	±30%	1.06	-100% to +800%	1.6E-05	-10% to +1000%	Tonnes/thousand cubic meters offshore oil production

TABLE 4.2.4A (NEW) (CONTINUED)
TIER 1 EMISSION FACTORS FOR OIL PRODUCTION, 1.B.2.A.II

a. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), and data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP) (United States Environmental Protection Agency (EPA) 2017), as applied in the 2018 U.S. GHG Inventory (United States Environmental Protection Agency (EPA) 2018a) to calculate emissions for the year 1992 (when EPA/GRI study was conducted). Examples of higher-emitting technologies and practices include venting of associated gas and uncontrolled tanks. NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from *IPCC 2006 GL* by calculating a ratio of N_2O to CO_2 from *IPCC 2006*, which was then applied to corresponding CO_2 values in this table.

b. Emission factors for CH_4 and CO_2 developed from data reported to the GHGRP (United States Environmental Protection Agency (EPA) 2017), and EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), as applied in the 2018 U.S. GHG Inventory to calculate emissions for the year 2016 (the most recent year of GHGRP data availability). Examples of lower-emitting technologies and practices include limited venting or flaring of associated gas, and tanks with controls. NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from *IPCC 2006 GL* by calculating a ratio of N_2O to CO_2 from *IPCC 2006*, which was then applied to corresponding CO_2 values in this table.

c. Emission factors developed from An Inventory of GHG, CAC and Other Priority Emissions by the Canadian Oil Sands Industry: 2015, prepared by Clearstone Engineering Ltd. for Environment and Climate Change Canada (Clearstone Engineering Ltd 2017) and production data from the Alberta Energy Regulator (AER) (Alberta Energy Regulator 2018), ST39: Alberta Mineable Oil Sands Plant Statistics. Includes fugitive emissions from tailings ponds and the exposed oil sands mine surface.

d. Emission factors developed from An Inventory of GHG, CAC and Other Priority Emissions by the Canadian Oil Sands Industry: 2015, prepared by Clearstone Engineering Ltd. for Environment and Climate Change Canada (Clearstone Engineering Ltd 2017) and production data from the Alberta Energy Regulator (AER) (Alberta Energy Regulator 2018), ST39: Alberta Mineable Oil Sands Plant Statistics.

e. Emission factors for CH_4 and CO_2 developed from U.S. Bureau of Ocean Energy Management's (BOEM) Gulf Offshore Activity Data System (GOADS) (United States Bureau of Ocean Energy Management (BOEM) 2017), as applied in the 2018 U.S. GHG Inventory, to estimate emissions for 2011 (the year of the BOEM survey), with U.S. GHG Inventory flaring data adjusted to use GOADS data and separate between oil and gas based on relative CH_4 emissions. NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from *IPCC 2006 GL* by calculating a ratio of N_2O to CO_2 from *IPCC 2006*, which was then applied to corresponding CO_2 values in this table.

1 B 2 a iii Transport.

This segment includes venting and leakage emissions related to the transport of marketable crude oil (including conventional, heavy and synthetic crude oil and bitumen), etc. to upgraders and refineries. The transportation systems may comprise pipelines, marine tankers, tank trucks and rail cars. Evaporation losses from storage, filling and unloading activities and fugitive equipment leaks are the primary sources of these emissions. Two sets of factors are available for tanker ships. Where tanker ship use of VRU is infrequent or unknown, the factor for "Loading of offshore production on tanker ships without VRU" should be used. Where tanker ship use of VRU is common, the factor for "Loading of offshore production on tanker ships with VRU" should be used.

For each segment/sub-segment listed in Table 4.2.4b below that is occurring in the country, compilers must calculate emissions, and sum them according to Equation 4.2.11. It is recognized that not all countries will have all segments and sub-segments occurring.

EQUATION 4.2.11 (NEW)

GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM OIL TRANSPORTATION

$$E_{oil\ transport} = A_{pipelines} \bullet EF_{pipelines}$$
$$+ A_{tanker\ trucks\ and\ rail\ cars} \bullet EF_{tanker\ trucks\ and\ rail\ cars}$$
$$+ A_{tanker\ ships} \bullet EF_{tanker\ ships}$$

Where:

$E_{oil\ transport}$ = Total amount of GHG gas emitted due to all relevant oil transport activities

$A_{pipelines}$ = Volume of oil transported by pipelines

$EF_{pipelines}$ = Emission factor for oil transported by pipelines

$A_{tanker\ trucks\ and\ rail\ cars}$ = Volume on oil transported by tanker trucks and rail cars

$EF_{tanker\ trucks\ and\ rail\ cars}$ = Emission factor for oil transported by tanker trucks and rail cars

A_{tanks} = Volume of crude oil feed

EF_{tanks} = Emission factor for tanks

$A_{tanker\ ships}$ = Volume of oil loaded onto tanker ships

$EF_{tanker\ ships}$ = Emission factor for oil transported by tanker ships

TABLE 4.2.4B (NEW)
TIER 1 EMISSION FACTORS FOR OIL TRANSPORT, 1.B.2.A.III

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Oil Transport	Pipelines[a]	All	0.0054	±100%	0.00049	±100%	0.054	-50% to +200%	NA	NA	Tonne per thousand cubic meters oil transported by pipeline
Oil Transport	Tanker Trucks and Rail Cars[b]	All	0.025	±50%	0.0023	±50%	0.25	-50% to +200%	NA	NA	Tonne per thousand cubic meters oil transported by tanker truck or rail car
Oil Transport	Tanks[c]	All	0.002	±50%	NA	NA	NA	NA	NA	NA	Tonne per thousand cubic meters crude oil feed
Oil Transport	Loading of offshore production on tanker ships without VRU[d]	All	0.093	±50%	ND	ND	ND	ND	ND	ND	Tonne per thousand cubic meters oil loaded onto tanker ship
Oil Transport	Loading of offshore production on tanker ships with VRU[e]	All	0.068	±50%	ND	ND	ND	ND	ND	ND	Tonne per thousand cubic meters oil loaded onto tanker ship

NA – Not Applicable, ND – Not Determined

a. From 2006 GL values for both developed and developing and economies in transition.

b. From 2006 GL values for both developed and developing and economies in transition.

c. Emission factors for CH_4 developed from and (Radian International LLC 1999), as applied in the 2018 U.S. GHG Inventory (United States Environmental Protection Agency (EPA) 2018a) for all years.

d. Emission factors for CH_4 developed from (Norwegian Environment Agency *et al.* 2017) GHG Inventory implied emission factors for 1990-2000, for loading of offshore production on tanker ships without vapour recovery units (VRU). Data from the years 1990-2000 were selected because these years are considered to include minimal use of VRU.

e. Emission factors for CH_4 developed from (Norwegian Environment Agency *et al.* 2017) GHG Inventory implied emission factors for 2001-2016, for loading of offshore production on tanker ships with VRU. Data from the years 2001-2016 were selected because these years are considered to include greater use of VRU.

1 B 2 a iv Refining

This segment includes fugitive emissions (including leaks, venting, and flaring) at petroleum refineries. Refineries process crude oils, natural gas liquids and synthetic crude oils to produce final refined products (e.g., primarily fuels and lubricants) and in some plants even hydrogen (see Box 4.2.1 below). Methane emission sources include storage tanks, blowdowns, asphalt blowing, equipment leaks, vents, loading operations, wastewater treating, cooling towers, catalytic cracking/reforming/fluid cracking, flares, delayed coking, and coke calcining. Carbon dioxide emissions included under 1.B.2.a.iv include asphalt blowing, calcination, anode production, process vents, and flaring. For additional information on catalyst regeneration and calcination, see Box 4.2.2. Where refineries are integrated with other facilities (for example, upgraders or co-generation plants) their relative emission contributions can be difficult to establish in measurement studies. The emission factors presented in Table 4.2.4c represent petroleum refinery emissions only.

BOX 4.2.1 (NEW)
HYDROGEN PRODUCTION. FUGITIVE EMISSIONS AND REFINERIES

When hydrogen is produced as a by-product or intermediate product in *Refineries*, it is *good practice* to report the greenhouse gas emissions (stationary and fugitive) in the **Energy sector** (Methodology can be adopted from Chapter 3.11 Volume 3).

When hydrogen is produced as main product at a stand-alone facility, the methodological guidance to estimate greenhouse gas emissions is given in IPPU Sector (see **Chapter 3.11 Volume 3 of *2019 Refinement*)**.

Inventory compilers should avoid double counting or omitting emissions from hydrogen production.

BOX 4.2.2 (NEW)
NOTES ON CATALYST REGENERATION AND CALCINATION

The process-related coke deposit at the catalyst leads to less effectiveness. With the coke burn-off, the catalyst is regenerated. The controlled **burn-off of the catalyst coke** takes place within the refinery and the thermal energy is usually re-used. Carbon dioxide emissions from this process are reported under **1.A.1.b.** It is *good practice* to develop a country specific emission factor. As activity data, the relevant quantity of petroleum coke could be obtained from the national petroleum statistic or the emission trading system (ETS), as applicable. If this information is not available, a default emission factor of **28.3 kg CO_2/t crude oil input**[6] can be used.

During **calcination**, the hydrocarbons contained in the petroleum coke are burned at high temperatures in order to obtain calcine (calcined coke). The emissions arising in this process are reported under **1.B.2.a.iv.** The default factor specified in Table 4.2.4c includes calcination.

[6] Emission factor developed as an average of (German Government 2018) GHG Inventory data (2005 to 2016) with a range of 25.7 to 31.0 kg CO_2/tonne.

TABLE 4.2.4C (NEW)
TIER 1 EMISSION FACTORS FOR OIL REFINING, 1.B.2.A.IV

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Oil Refining	All[a]	All	0.03	-50 to +130%	5.85	-50 to +130%	0.26	±100%	8.77E-05	±100%	Tonnes/thousand cubic meters oil refined

a. Emission factors for CH_4, NMVOC, and CO_2 developed as an average of (German Government 2018) GHG Inventory data (1990 to 2016) with a range of 0.016 to 0.065 tonnes CH_4/thousand cubic meters, 0.151 to 0.584 tonnes NMVOC/thousand cubic meters and 5.437 to 6.143 tonnes CO_2/thousand cubic meters. N_2O values were developed from *IPCC 2006 GL* by calculating a ratio of N_2O to CO_2 from oil production (N_2O values from refineries were unavailable) in *IPCC 2006*, which was then applied to corresponding CO_2 values for refineries in this table. The factors include fugitive equipment leaks, flaring, storage of crude oil, handling and calcination.

1 B 2 a v Distribution of Oil Products

This segment includes fugitive emissions (including leaks and venting) from the transport and distribution of refined products, including those at bulk terminals and retail facilities. Evaporation losses from storage, filling and unloading activities and equipment leaks are the primary sources of these emissions. Many products are directly used in the chemical industry and should be considered in the appropriate subcategory (e.g. Volume 3 Chapter 3). Table 4.2.4d below provides emission factors for major fuel types. The emission factors consider emissions from refinery dispatch or border dispatch stations, to depots and further distribution to end-users (e.g. gas stations and airports). It is assumed that a fractional distillation in the refinery separated gaseous components from fuels. Therefore, only NMVOC emissions factors are provided. Tier 1 emission factors are currently available for only a subset of the total types of oil products distributed.

For each sub-segment listed in Table 4.2.4d below that is occurring in the country, compilers must calculate emissions, and sum them according to Equation 4.2.12. It is recognized that not all countries will have all segments and sub-segments occurring.

EQUATION 4.2.12 (NEW)
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM DISTRIBUTION OF OIL PRODUCTS

$$E_{distribution\ of\ oil\ productions} = A_{gasoline\ distribution} \bullet EF_{gasoline\ distribution} + A_{other\ distribution} \bullet EF_{other\ distribution}$$

Where:

$E_{distribution\ of\ oil\ productions}$ = Total amount of GHG gas emitted due to all relevant activities on distribution of oil products

$A_{gasoline\ distribution}$ = Volumes of gasoline consumed

$EF_{gasoline\ distribution}$ = Emission factor for gasoline distribution

$A_{other\ distribution}$ = Volumes of other oil products consumed (e.g. diesel, aviation fuel, jet kerosene)

$EF_{other\ distribution}$ = Emission factor for other oil products distribution (e.g. diesel, aviation fuel, jet kerosene)

TABLE 4.2.4D (NEW)
TIER 1 EMISSION FACTORS FOR DISTRIBUTION OF OIL PRODUCTS, 1.B.2.A.V

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Refined Product Distribution	Gasoline[a]	All	NA	NA	NA	NA	2.27	±20%	NA	NA	Tonnes per thousand cubic meters product consumed
Refined Product Distribution	Other (e.g. diesel, aviation fuel, jet kerosene)[b]	All	NA	NA	NA	NA	0.15	±20%	NA	NA	Tonnes per thousand cubic meters product consumed

NA – Not Applicable

a. The NMVOC emission factors are developed from the (German Government 2018) inventory values for 2016 for unabated distribution of fuels and include transhipping from tanker to tanks, refuelling of cars, permeation in refuelling hoses and dripping losses. Several techniques like vapour-balancing and vapour-recovery along with use of automatic monitoring systems will have a significant influence on the factor, in which country-specific EFs should be developed to reflect reduction efficiency and level of application of such techniques.

b. Note from *2006 IPCC Guidelines*: “Estimated based on assumed average evaporation losses of 0.15 percent of throughput at the distribution terminal and additional losses of 0.15 percent of throughput at the retail outlet. These values will be much lower where Stage 1 and Stage 2 vapour recovery occurs and may be much greater in warmer climates.”

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1 B 2 a vi Other

This segment includes fugitive emissions (leaks, venting and flaring) from oil systems that are not otherwise accounted for in the other categories. This includes fugitive emissions from spills and other accidental releases, waste oil treatment facilities and oilfield waste disposal facilities.

Anomalous leak events can occur across oil systems and can have highly variable emissions. Examples of such events include releases from emergency pressure relieving equipment such as emergency shutdowns (ESD), emergency safety blowdowns (ESB) and breakout/surge tanks (American Petroleum Institute (API) 2009). It is *good practice* to quantify and report such emissions whenever possible under 1 B 2 a vi (“Other”). There is no Tier 1 method available for such events, which need to be evaluated on a case-by-case basis, often using a combination of emission factors and engineering calculations. An example of calculating emissions during emergency conditions though an engineering calculation approach is given in (American Petroleum Institute (API) 2009).

1 B 2 a vii Abandoned Oil Wells

When production activities are completed, oil and gas wells may be abandoned. Several reasons of well abandonment exist: if wells have fulfilled their purpose; after the surrender of a production license; due to geological reasons; due to technical reasons; due to technological, ecological and other reasons. Countries with a long history of oil and gas production may have a significant abandoned well population and should estimate emissions for this source.

For onshore wells ending production in recent decades, the abandonment process is often covered by national (or regional) well abandonment regulations. Regulated wells are often treated with plugging and other practices prior to abandonment/decommissioning to prevent leakage from the wells and migration of oil, gas or brine to surrounding strata. That process can be generally described as follows. The wells are plugged (with the use of plugging materials, e.g. cement) and sealed according to the regulations and considering reasons of decommissioning, geological conditions, and other well specifics. If these steps are implemented effectively and the long-term integrity of the well does not fail over time, it is unlikely that the well will leak substantial amounts of methane. However, in practice integrity failure of some abandoned wells may occur and the well may start leaking methane to the atmosphere. This is consistent with findings of recent studies in the U.S. and U.K., which have found that the majority of effectively plugged wells are not leaking, but a small number will have some emissions (e.g., (Townsend-Small *et al.* 2016), (Kang *et al.* 2016), (Boothroyd *et al.* 2016)).

Tier 1 default emission factors are presented in Table 4.2.4e. All of the presented emission factors are expressed in units of mass of emissions per abandoned well. All the EFs are developed from data for both abandoned oil and gas wells. It should be noted that factors provided for both oil and gas wells have high uncertainty, which is reflected in the uncertainty ranges provided in the table. The EFs of abandoned wells are split into either “plugged” (or, properly decommissioned per regulations) and “unplugged” well sub-segments. The distinction requires the number of each type of abandoned well (plugged or unplugged). Existing data on abandoned oil and gas wells as well as practices for their plugging status may be limited and/or difficult to collect. If insufficient data on plugging practices is available to disaggregate activity data in such a way, the default EF for all type wells is to be used. More limited data are available on offshore wells and disaggregated (i.e. plugged versus unplugged) factors for offshore abandoned wells are developed from onshore wells data considering that most methane (around 98%) from offshore abandoned wells is dissolved in marine water.

Based on available data, emission factors (and leak frequency) do not vary over the time series per well; according to the latest research, well integrity failure rate shows no significant trend over time. If failures do exist, they more likely occur early on in the decommissioned life of a well (Boothroyd *et al.* 2016). Based on the latest research, gas well emission rates may be higher than oil well emissions rates. However, due to limited data points in the currently available data, Tier 1 EFs were not disaggregated into oil-specific and gas-specific factors. In cases where national circumstances are different from listed above, a country should consider using a Tier 2 or Tier 3 approach.

Activity data for this source are counts of abandoned onshore and offshore wells in each year of the time series, and for onshore wells, the fraction of wells that are effectively plugged. It may be challenging to compile a total national count of abandoned wells and to assess whether wells are plugged or unplugged. The compiler should review national, local, or regional records and consult with industry to develop an estimate. There is also likely significant variation between post-well closure practices internationally and even within countries.

TABLE 4.2.4E (NEW)
TIER 1 EMISSION FACTORS FOR ABANDONED OIL WELLS, 1.B.2.A.VII

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Abandoned wells	Onshore: Plugged[a]	Leaks	2.0E-05	-87% to +130%	NA	NA	NA	NA	NA	NA	Tonnes CH_4/ onshore plugged abandoned well
	Onshore: Unplugged[a]	Leaks	8.8E-02	-99% to +150%	NA	NA	NA	NA	NA	NA	Tonnes CH_4/ onshore unplugged abandoned well
	Onshore: All wells (plugged and unplugged)[a, b]	Leaks	1.2E-02	-83% to +124%	NA	NA	NA	NA	NA	NA	Tonnes CH_4/ onshore abandoned well
Abandoned wells	Offshore: Plugged[c]	Leaks	3.5E-07	-87% to +130%	NA	NA	NA	NA	NA	NA	Tonnes CH_4/ offshore plugged abandoned well
	Offshore: Unplugged[c]	Leaks	1.8E-03	-99% to +150%	NA	NA	NA	NA	NA	NA	Tonnes CH_4/ offshore unplugged abandoned well
	Offshore: All wells (plugged and unplugged)[c]	Leaks	2.4E-04	-83% to +124%	NA	NA	NA	NA	NA	NA	Tonnes CH_4/ offshore abandoned well

NA – Not Applicable

a. From (Townsend-Small *et al.* 2016), which includes data collected from wells across the U.S.

b. It should be noted that the emission factors for “All wells (plugged and unplugged)” uses (Townsend-Small *et al.* 2016) data set plugging rate of 86.2%.

c. Developed by using the onshore abandoned wells emission factors in this table, and applying a factor of 0.02 to reflect that most methane from such wells is dissolved in marine water. Factor of 0.02 based on (Vielstädte *et al.* 2015; United States Environmental Protection Agency (EPA) 2018b).

Natural Gas Systems

1 B 2 b i Exploration

This segment includes fugitive emissions (including equipment leaks, venting and flaring) from gas field activities prior to production (e.g., prospecting and exploratory well drilling, well/drill stem testing, and well completions).[7] In this segment, factors are not disaggregated to drilling, testing and servicing operation; EFs are applied to the whole segment.

In Table 4.2.4f several options for onshore exploration emission factors inclusive of venting, flaring and leaks are presented. Each technology/practice-specific emission factor is presented in units of tonne per gas well drilled, tonne per active gas well, and in tonnes per million cubic meter gas produced. The count of wells drilled is thought to best reflect emissions from exploration and if available should be applied. However, the inventory compiler should assess which activity data are available and which activity data basis best reflects emissions in that segment for that country.

Emission factors are available for both onshore unconventional and onshore conventional gas exploration. Offshore exploration emissions data are unavailable, and these emissions are thought to be negligible; therefore, emission factors are not included for offshore exploration. Here, unconventional gas exploration refers to exploration where hydraulic fracturing well completion practices are used, and conventional gas exploration refers to exploration where hydraulic fracturing well completion practices are not used.

The extent of any hydraulic fracturing activities in the country should be assessed. A potential data source for this assessment is the International Energy Agency's database for unconventional gas production (International Energy Agency (IEA) 2018). Unconventional completions (i.e., conducted with hydraulic fracturing) have a different emissions profile than conventional completions (i.e., conducted without hydraulic fracturing). This is reflected in the emission factors below. Where possible, the compiler should separate national activity data into conventional and unconventional and apply the relevant emission factors. If only total gas wells or total gas production data are available, the compiler should develop an estimate of the annual split between conventional and unconventional wells or conventional and unconventional production in the country to develop the activity data.

Unconventional factors are to be applied to the unconventional activity data basis. Where wells drilled are completed with hydraulic fracturing and flaring and gas recovery is not practiced, or where the extent of flaring or recovery practices is unknown, the first set of factors ("Unconventional gas exploration without flaring or gas capture") should be used and applied to the relevant activity data (i.e. unconventional wells drilled, total unconventional well population, or unconventional production). Where wells drilled are completed with hydraulic fracturing and flaring and gas recovery is used, the fraction of the relevant activity data that uses flaring and/or gas recovery should be determined. The second set of factors ("Unconventional gas exploration with flaring or gas capture") is used for that fraction, while the first set of factors is applied to the wells or production that is not using flaring or recovery. Conventional factors ("Conventional Gas exploration") are to be applied to the conventional activity data basis. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series. For each segment/sub-segment listed in Table 4.2.4f below that is occurring in the country, compilers must calculate emissions, and sum them according to Equation 4.2.13. It is recognized that not all countries will have all segments and sub-segments occurring. Factors listed in Table 4.2.4f apply to onshore exploration. Emissions data are unavailable for offshore exploration.

Factors presented are inclusive of venting, flaring, and leak emissions. For cases where country-specific data are available for a subcomponent of the factor (e.g. venting and flaring emissions), disaggregated Tier 1 EF that could be applied to estimate the remaining emission types are available—see Annex 4A.2 for information (including examples) on how to calculate disaggregated emissions.

Definitions for oil wells versus gas wells can vary from country to country and organization to organization. The Tier 1 EFs in the table below were developed from emissions occurring in U.S. basins identified as having predominantly gas production. Emission factors were developed using data on exploration emissions (drilling, testing, and completions) for wells with a gas oil ratio of >17,000 cubic meters gas to cubic meters oil. If national criteria defines oil and gas wells, follow the national criteria or national documentation to make the distinction. What is most important is that all emissions are transparently allocated to either oil or gas systems, without omission.

For each sub-segment listed in Table 4.2.4f below that is occurring in the country, compilers must calculate emissions, and sum them according to Equation 4.2.13. It is recognized that not all countries will have all sub-

[7] Refracturing and redrilling emissions are to be included in 1.B.2.a.ii (Production and Upgrading).

segments (i.e. technologies or practices) occurring. Factors listed in Table 4.2.4f apply to onshore exploration. Emissions data are unavailable for offshore exploration.

EQUATION 4.2.13 (NEW)
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM EXPLORATION

$$E_{exploration} = A_{unconventional\ gas\ without\ flaring\ or\ recovery} \bullet EF_{unconventional\ gas\ without\ flaring\ or\ recovery} + A_{unconventional\ gas\ with\ flaring\ or\ recovery} \bullet EF_{unconventional\ gas\ with\ flaring\ or\ recovery} + A_{conventional\ gas} \bullet EF_{conventional\ gas}$$

Where:

$E_{exploration}$ = Total amount of GHG gas emitted due to all relevant natural gas exploration activities

$A_{unconventional\ gas\ without\ flaring\ or\ recovery}$ = Activity data on exploration of unconventional natural gas without flaring or recovery

$EF_{unconventional\ gas\ without\ flaring\ or\ recovery}$ = Emission factor for exploration of unconventional natural gas without flaring or recovery

$A_{unconventional\ gas\ with\ flaring\ or\ recovery}$ = Activity data on exploration of unconventional natural gas with flaring or recovery

$EF_{unconventional\ gas\ with\ flaring\ or\ recovery}$ = Emission factor for exploration of unconventional natural gas with flaring or recovery

$A_{conventional\ gas}$ = Activity data on exploration of conventional natural gas

$EF_{conventional\ gas}$ = Emission factor for exploration of conventional natural gas

TABLE 4.2.4F (NEW)
TIER 1 EMISSION FACTORS FOR NATURAL GAS EXPLORATION SEGMENT, 1.B.2.B.I

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Gas Exploration	Onshore unconventional gas exploration without flaring or gas capture[a, d]	All	20.1	±20%	1.50	±20%	3.01	-12.5 to +800%	NA	NA	Tonnes/unconventional onshore gas wells drilled in a year, without flaring or recovery
			4.35	±20%	0.32	±20%	0.65	-12.5 to +800%	NA	NA	Tonnes/total unconventional onshore gas well population where exploration occurs without flaring or recovery
			2.52	±20%	0.19	±20%	0.38	-12.5 to +800%	NA	NA	Tonnes/million cubic meters onshore unconventional onshore gas production where exploration occurs without flaring or recovery
Gas Exploration	Onshore unconventional gas exploration with flaring or gas capture[b, d]	All	1.30	±20%	47.0	±20%	0.19	-12.5% to +800%	3.4E-04	-10% to +1000%	Tonnes/unconventional onshore gas wells drilled in a year, with flaring or recovery
			0.05	±20%	1.93	±20%	0.0071	-12.5% to +800%	1.4E-05	-10% to +1000%	Tonnes/total unconventional onshore gas well population where exploration occurs with flaring or recovery
			0.08	±20%	3.16	±20%	0.013	-12.5% to +800%	2.3E-05	-10% to +1000%	Tonnes/million cubic meters onshore unconventional gas production where exploration occurs with flaring or recovery

TABLE 4.2.4F (NEW) (CONTINUED)
TIER 1 EMISSION FACTORS FOR NATURAL GAS EXPLORATION SEGMENT, 1.B.2.B.I

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Gas Exploration	Onshore conventional Gas exploration[c]	All	5.78	±20%	4.72	±20%	0.87	-12.5% to +800%	3.4E-05	-10% to +1000%	Tonnes/onshore conventional gas wells drilled in a year
			0.03	±20%	0.03	±20%	5.2E-03	-12.5% to +800%	2.2E-07	-10% to +1000%	Tonnes/total conventional onshore gas well population
			0.06	±20%	0.05	±20%	8.6E-03	-12.5% to +800%	3.6E-07	-10% to +1000%	Tonnes/million cubic meters onshore conventional gas production

NA – Not Applicable

a. Emission factors for CH_4 and CO_2 developed from data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP) (United States Environmental Protection Agency (EPA) 2017) for unconventional completions and well testing, and (Radian International LLC 1999), for drilling emissions, as applied in the 2018 U.S. GHG Inventory (United States Environmental Protection Agency (EPA) 2018a). Factor is the average of 2006-2010 calculated implied emission factors for emissions from well drilling, well testing, and from well completions with hydraulic fracturing that do not flare or use gas capture. The time period of 2006-2010 was selected as it represents a time when hydraulic fracturing is occurring, but before state or federal regulations were in place to control gas emissions. NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table.

b. Emission factors for CH_4 and CO_2 developed from data reported to the GHGRP (United States Environmental Protection Agency (EPA) 2017) for unconventional completions and well testing, and from (Radian International LLC 1999) for drilling emissions, as applied in the 2018 U.S. GHG Inventory. Factor is the average of 2013-2016 calculated implied emission factors for emissions from well drilling, well testing, and from well completions with hydraulic fracturing that flare or use gas capture. The time period of 2013-2016 was selected as it represents a time when hydraulic fracturing is occurring and state or federal regulations were in place to control gas emissions. NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from *IPCC 2006 GL* by calculating a ratio of N_2O to CO_2 from *IPCC 2006*, which was then applied to corresponding CO_2 values in this table.

c. Emission factors for CH_4 and CO_2 developed from GHGRP (United States Environmental Protection Agency (EPA) 2017) for conventional completions and well testing, and (Radian International LLC 1999), for drilling emissions, as applied in the 2018 U.S. GHG Inventory. Factor is the average of 2006-2016 calculated implied emission factors for emissions from well drilling and from conventional completions. The time period of 2006-2016 was selected to cover the time frame of the other exploration factors. NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from *IPCC 2006 GL* by calculating a ratio of N_2O to CO_2 from *IPCC 2006*, which was then applied to corresponding CO_2 values in this table.

d. Unconventional gas exploration refers to exploration that includes well completions with hydraulic fracturing. Conventional gas exploration emission factors should be applied where hydraulic fracturing well completion practices are not used.

1 B 2 b ii Production and Gathering

This segment includes fugitive emissions (including leaks, venting and flaring) from the gas wellhead through to the inlet of gas processing plants, or, where processing is not required, to the tie-in points on gas transmission systems. In the production stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves (e.g., as wellhead leaks and from well workovers and refractures), and well-site equipment such as pneumatic controllers, dehydrators and separators. Gathering and boosting emission sources are included within the production sector. The gathering and boosting sources include gathering and boosting stations (with multiple emission sources on site, such as compressors, pneumatic controllers and tanks) and gathering pipelines. The gathering and boosting stations receive natural gas from production sites and transfer it, via gathering pipelines, to processing facilities or transmission pipelines.

The table below presents factors for onshore gas production, gathering systems, and offshore gas production[8].

Countries with onshore gas production should apply a factor for onshore production and the factor for gathering to the quantity of onshore gas produced in each year.

Factors for onshore gas production (other than coal bed methane) are presented both in units of tonne per active gas well, and in tonnes per million cubic meter gas produced. The count of wells is thought to best reflect emissions from oil production, and if complete and accurate well count data are available, they should be applied. However, the inventory compiler should assess which activity data are available and which activity data basis best reflects emissions in that segment for that country. The types of technologies and practices in use in the country should be assessed, including extent of lower-emitting liquids unloading practices for any liquids unloading occurring, and extent of leak detection and repair (LDAR) practices. Where this information is unknown, or where there is limited use of lower-emitting technologies (i.e., more than 60% of any liquids unloading is conducted without venting or with lower-emitting plunger lifts or LDAR is not used extensively), the first set of emission factors ("Most activities occurring with higher-emitting technologies and practice") for onshore gas production should be used. Where lower-emitting technologies are used extensively, the second set of emission factors ("most activities occurring with lower-emitting technologies and practices") for gas production should be used. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series.

The emission factors for onshore production were developed from data sets that included a mix of production from wells in conventional formations and wells in unconventional formations and are considered to be applicable to both. However, if data on coal bed methane production are available, the factor for coal bed methane production may be applied to the portion of gas production that is from coal bed methane.

Countries with offshore gas production should apply a factor for offshore gas production. If no data are available to estimate the share of gas production that occurs offshore, the EF for onshore production should be applied to the total quantity of gas production.

Factors presented are inclusive of venting, flaring, and leak emissions. For cases where country-specific data are available for a subcomponent for the factor (e.g. venting and flaring emissions), disaggregated Tier 1 EF that could be applied to estimate the remaining emission types are available—see Annex 4A.2 for information (including examples) on how to calculate disaggregated emissions.

Definitions for oil wells versus gas wells can vary from country to country and organization to organization. The onshore production (other than coal bed methane) Tier 1 EFs in the table below were developed from emissions occurring in U.S. basins identified as having predominantly gas production. Emission factors were developed using data on production emissions for wells with a gas oil ratio of >17,000 cubic meters gas to cubic meters oil. If national criteria defines oil and gas wells, follow the national criteria or national documentation to make the distinction. What is most important is that all emissions are transparently allocated to either oil or gas systems, without omission.

For each sub-segment listed in Table 4.2.4g below that is occurring in the country, compilers must calculate emissions, and sum them according to Equation 4.2.14. It is recognized that not all countries will have all segments and sub-segments occurring.

[8] While the emission factor options are meant to cover technologies and practices that are common in the oil and gas industries internationally, technologies and practices can vary significantly between regions and over time. A country should periodically assess changes in technologies and practices, and changes in available emissions data, and consider updating estimates using a Tier 2 approach, per *good practice*.

EQUATION 4.2.14 (NEW)
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM GAS PRODUCTION AND GATHERING

$$E_{production} = A_{onshore\ gas\ production} \bullet EF_{onshore\ gas\ production}$$
$$+ A_{onshore\ coal\ bed\ production} \bullet EF_{onshore\ coal\ bed\ production}$$
$$+ A_{gathering} \bullet EF_{gathering}$$
$$+ A_{offshore\ gas\ production} \bullet EF_{offshore\ gas\ production}$$

Where:

$E_{production}$ = Total amount of GHG gas emitted due to all relevant natural gas production activities

$A_{onshore\ gas\ production}$ = Volume of onshore gas produced/active gas well

$EF_{onshore\ gas\ production}$ = Emission factor for onshore gas produced

$A_{onshore\ coal\ bed\ production}$ = Volume of onshore gas produced

$EF_{onshore\ coal\ bed\ production}$ = Emission factor for onshore coal bed production

$A_{gathering}$ = Volume of onshore gas produced

$EF_{gathering}$ = Emission factor for gathering of natural gas produced

$A_{offshore\ gas\ production}$ = Volume of offshore gas produced

$EF_{offshore\ gas\ production}$ = Emission factor for offshore gas produced

TABLE 4.2.4G (NEW)
TIER 1 EMISSION FACTORS FOR NATURAL GAS PRODUCTION SEGMENT, 1.B.2.B.II

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Gas Production	Onshore: Most activities occurring with higher-emitting technologies and practices[a]	All	4.09	±20%	1.45	±20%	0.98	-75% to +250%	2.5E-05	-10% to +1000%	Tonnes/million cubic meters onshore gas production
			7.07	±20%	2.51	±20%	1.70	-75% to +250%	4.3E-05	-10% to +1000%	Tonnes/active gas well
Gas Production	Onshore: Most activities occurring with lower-emitting technologies and practices[b]	All	2.54	±20%	3.60	±20%	0.61	-75% to +250%	6.1E-05	-10% to +1000%	Tonnes/million cubic meters onshore gas production
			4.37	±20%	6.21	±20%	1.05	-75% to +250%	1.1E-04	-10% to +1000%	Tonnes per active gas well
Gas Production	Onshore Coal Bed Methane[c]	All	1.95	±20%	19.57	±20%	0.23	-75% to +250%	7.2E-04	-10% to +1000%	Tonnes/million cubic meters onshore gas production
Gas Production	Gathering[d]	All	3.20	±10%	0.35	±10%	0.77	-75% to +250%	6.0E-06	-10% to +1000%	Tonnes/million cubic meters onshore gas production
Gas Production	Offshore[e]	All	2.94	±20%	4.80	±20%	0.70	-75% to +250%	8.2E-05	-10% to +1000%	Tonnes/million cubic meters offshore gas production

TABLE 4.2.4G (NEW) (CONTINUED)
TIER 1 EMISSION FACTORS FOR NATURAL GAS PRODUCTION SEGMENT, 1.B.2.B.II

a. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), and data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP) (United States Environmental Protection Agency (EPA) 2017), as applied in the 2018 U.S. GHG Inventory (United States Environmental Protection Agency (EPA) 2018a) to calculate emissions for the year 1992 (when EPA/GRI study was conducted). Examples of higher-emitting technologies and practices include venting for liquids unloading without plunger lifts, unconventional workovers that vent, and use of high-bleed pneumatic controllers. NMVOC values were developed from IPCC 2006 GL by calculating a ratio of NMVOC to CH_4 from IPCC 2006, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from IPCC 2006 GL by calculating a ratio of N_2O to CO_2 from IPCC 2006, which was then applied to corresponding CO_2 values in this table.

b. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), and data reported to the GHGRP, as applied in the 2018 U.S. GHG Inventory to calculate emissions for the year 2016 (the most recent year of GHGRP (United States Environmental Protection Agency (EPA) 2017) data availability). Examples of lower-emitting technologies and practices include venting for liquids unloading with plunger lifts, unconventional workovers using reduced emission completion technologies, and low-bleed pneumatic controllers. NMVOC values were developed from IPCC 2006 GL by calculating a ratio of NMVOC to CH_4 from IPCC 2006, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from IPCC 2006 GL by calculating a ratio of N_2O to CO_2 from IPCC 2006, which was then applied to corresponding CO_2 values in this table.

c. Emission factors for CH_4 and CO_2 developed from data reported to the Australian National Greenhouse and Energy Reporting program (NGER) (Australian Government Clean Energy Regulator 2017), as applied in Australian National Inventory (Australian Government 2018) and is the average of emissions for the years 2016-17.

d. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), and (Marchese *et al.* 2015), as applied in the 2018 U.S. GHG Inventory (United States Environmental Protection Agency (EPA) 2018a) to calculate emissions for the year 2012 (when the measurements used in Marchese were conducted). NMVOC values were developed from IPCC 2006 GL by calculating a ratio of NMVOC to CH_4 from IPCC 2006, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from IPCC 2006 GL by calculating a ratio of N_2O to CO_2 from IPCC 2006, which was then applied to corresponding CO_2 values in this table.

e. Emission factors for CH_4 and CO_2 developed from U.S. Bureau of Ocean Energy Management's (BOEM) Gulf Offshore Activity Data System (GOADS) (United States Bureau of Ocean Energy Management (BOEM) 2017), as applied in the 2018 U.S. GHG Inventory, to estimate emissions for 2011 (the year of the BOEM survey), with U.S. GHG Inventory flaring data adjusted to use GOADS data directly and separation of CO_2 from flaring between oil and gas based on relative CH_4 emissions. NMVOC values were developed from IPCC 2006 GL by calculating a ratio of NMVOC to CH_4 from IPCC 2006, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from IPCC 2006 GL by calculating a ratio of N_2O to CO_2 from IPCC 2006, which was then applied to corresponding CO_2 values in this table.

1 B 2 b iii Processing

This segment includes fugitive emissions (including leaks, venting and flaring) from gas processing facilities. In this stage, natural gas liquids (NGLs) and various other constituents (e.g. sulphur) from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Emission sources include compressors, equipment leaks, pneumatic controllers, uncombusted gas from engines and flaring, and CO_2 from flaring and sour gas removal. In the Table 4.2.4h below, several options for emission factors are presented. For some emission factors, the factors are presented both in units of tonne per million cubic meter gas processed, and in tonnes per million cubic meter gas produced. The volume of gas processed is thought to best reflect emissions from gas processing, and if gas processing data are available, they should be applied. However, the inventory compiler should assess which activity data are available and which activity data basis best reflects emissions in that segment for that country. The extent of any leak detection and repair (LDAR) programs, and the use of dry seals in centrifugal compressors in the country should be assessed. Where this information is unknown, or where there are limited or no LDAR programs or less than 50% of centrifugal compressors have dry seals, the "without LDAR, and less than 50% of centrifugal compressors have dry seal" emission factors for Natural Gas Processing should be used. Where leak detection and repair programs are in use and around 50% of more of centrifugal compressors have dry seals, use the "Extensive LDAR, and around 50% or more of centrifugal compressors have dry seals" emission factors for Natural Gas Processing. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series. Where sour gas (or "acid gas") removal is occurring, the factor for that source should also be applied to the portion of gas processed with sour gas removal, and added to the overall gas processing total.

Factors presented are inclusive of venting, flaring, and leak emissions. Information for disaggregating the Tier 1 EFs for processing into leak, vent, and flare emissions is available in Annex 4A.2.

Town gas originates from outgassing of hard coal under air exclusion in retort furnace or chamber kilns. Emissions from these processes should be considered under Section 4.3 "Solid Fuel Transformation".

For each segment/sub-segment listed in Table 4.2.4h below that is occurring in the country, compilers must calculate emissions, and sum them according to Equation 4.2.15. It is recognized that not all countries will have all segments and sub-segments occurring. The emissions from gas processing ($E_{processing}$) are computed by multiplying the appropriate emission factor from Table 4.2.4h by the amount of gas processed (units of millions of cubic meter of gas). If sour gas is removed, this emission should be added to the overall processing emissions, where the emissions from sour gas removal is computed as the product of the emission factor for sour gas removal from Table 4.2.4h and the amount of sour gas that is processed (in units of millions of cubic meters of sour gas). The compiler should attempt to determine the fraction of the gas processed that is sour gas using nationally available statistics or industry information on the characteristics of processing plants. If no data is available, it is *good practice* to assume the fraction, for example by considering the study of (Burgers *et al.* 2011) or comparing to adjacent countries. If none of the proposals works, a value of 32% sour gas[9] can be applied.

EQUATION 4.2.15 (NEW)
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM GAS PROCESSING

$$E_{processing} = A_{gas\ processed} \bullet EF_{LDAR\ or\ no\ LDAR} + A_{sour\ gas\ processed} \bullet EF_{sour\ gas\ removal}$$

Where:

$E_{processing}$ = Total amount of GHG gas emitted due to all relevant natural gas processing activities

$A_{gas\ processed}$ = Volume of natural gas processed or produced

$EF_{LDAR\ or\ no\ LDAR}$ = Emission factor for gas processed with or without LDAR programs

$A_{sour\ gas\ processed}$ = Volume of sour gas processed

$EF_{sour\ gas\ removal}$ = Emission factor for sour gas processing

[9] Developed as an unweighted mean value from Germany (40%) and Austria (25%), from (German Government 2018) and (Austrian Government 2018) NIRs.

TABLE 4.2.4H (NEW)
TIER 1 EMISSION FACTORS FOR GAS PROCESSING SEGMENT, 1.B.2.B.III

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Processing	Without LDAR, or with limited LDAR, or 50% of centrifugal compressors are dry seal[a]	All	1.83	±10%	0.12	±10%	0.15	-75% to +250%	1.3E-06	-10% to +1000%	Tonnes/million cubic meters gas processed
			1.65	±10%	0.11	±10%	0.13	-75% to +250%	1.2E-06	-10% to +1000%	Tonnes/million cubic meters gas produced
Processing	Extensive LDAR, and around 50% or more of centrifugal compressors are dry seal[b]	All	0.75	±10%	9.45	±10%	0.06	-75% to +250%	1.0E-04	-10% to +1000%	Tonnes/million cubic meters gas processed
			0.57	±10%	7.21	±10%	0.05	-75% to +250%	7.9E-05	-10% to +1000%	Tonnes/million cubic meters gas produced
Processing	Sour gas (acid gas removal)[c]	All	0.1	±100%	66.7	±100%	0.15	-75% to +250%	1.3E-06	-10% to +1000%	Tonnes/million cubic meters sour gas processed

a. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), as applied in the 2018 U.S. GHG Inventory to calculate emissions for the year 1992 (when EPA/GRI study was conducted). Emissions from acid gas removal were deducted prior to EF development. NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from *IPCC 2006 GL* by calculating a ratio of N_2O to CO_2 from *IPCC 2006*, which was then applied to corresponding CO_2 values in this table.

b. Emission factors for CH_4 and CO_2 developed from data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP) (United States Environmental Protection Agency (EPA) 2017), and from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), as applied in the 2018 U.S. GHG Inventory to calculate emissions for the year 2016 (most recent year of GHGRP data availability). Emissions from acid gas removal were deducted prior to EF development. NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from *IPCC 2006 GL* by calculating a ratio of N_2O to CO_2 from *IPCC 2006*, which was then applied to corresponding CO_2 values in this table.

c. Emission factor s for CH_4 and CO_2 from the 2006 IPCC GL. NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table. N_2O values were developed from *IPCC 2006 GL* by calculating a ratio of N_2O to CO_2 from *IPCC 2006*, which was then applied to corresponding CO_2 values in this table.

1 B 2 b iv Transmission and Storage

This segment includes fugitive emissions (including leaks, venting and flaring) from systems used to transport processed natural gas to market (i.e., to industrial consumers and natural gas distribution systems), including natural gas storage systems. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities are used to move the gas throughout the transmission system. Emissions from natural gas liquids extraction plants on gas transmission systems should be reported as part of natural gas processing (Sector 1.B.2.b.iii). Fugitive emissions related to the transmission of natural gas liquids should be reported under 1.B.2.b.iv. Emissions sources include compressors, pneumatic controllers, storage wells, leaks and venting from transmission lines, and equipment leaks from compressor stations. This source also includes LNG stations and import and export terminals; further details on the LNG sector can be found in *Liquified Natural Gas (LNG) Operations: Consistent Methodology for estimating Greenhouse Gas Emissions* (American Petroleum Institute (API) 2015). In the table below, several options for emission factors are presented.

Factors for transmission are presented both in units of tonne per million cubic meter gas consumption, and in tonnes per km transmission pipeline. The length of transmission pipeline is thought to best reflect emissions from transmission, and if pipeline data are available, they should be applied. However, the inventory compiler should assess which activity data are available and which activity data basis best reflects emissions in that segment for that country. The extent of any leak detection and repair (LDAR) programs, and the use of dry seals in centrifugal compressors in the country should be assessed. Where this information is unknown, or where there are limited or no LDAR programs or less than 50% of centrifugal compressors have dry seals, the “Limited LDAR or less than 50% of centrifugal compressors have dry seals” emission factors for transmission should be used. Where leak detection and repair programs are in use and around 50% of more of centrifugal compressors have dry seals, use the “Extensive LDAR, and around 50% or more of centrifugal compressors have dry seals” emission factors for transmission. For gas storage, the extent of any leak detection and repair programs should be assessed. Where this information is unknown, or LDAR is not extensively practiced, the first set of emission factors for gas storage (“Limited LDAR or most activities occurring with higher-emitting technologies and practices”) should be used. Where there are extensive LDAR programs, the second set of emission factors for gas storage (“Extensive LDAR and most activities occurring with lower-emitting technologies and practices”) should be used.

Where LNG imports and exports or storage occur, the number of stations should be determined, and the emission factors for LNG should be used. See (American Petroleum Institute (API) 2015) for further elaboration of emission estimation methods for the LNG sector (e.g. Tiers 2 and 3).

As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series.

Factors presented are inclusive of venting, flaring, and leak emissions. Information for disaggregating the Tier 1 EF for transmission and storage into leak, vent, and flare emissions is available in Annex 4A.2.

For each sub-segment listed in Table 4.2.4i below that is occurring in the country, compilers must calculate emissions, and sum them according to Equation 4.2.16. It is recognized that not all countries will have all segments and sub-segments occurring.

EQUATION 4.2.16 (NEW)
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM GAS TRANSMISSION AND STORAGE

$$E_{\text{transmission and storage}} = A_{\text{transmission}} \bullet EF_{\text{transmission}} + A_{\text{storage}} \bullet EF_{\text{storage}} + A_{\text{LNG import/export}} \bullet EF_{\text{LNG import/export}} + A_{\text{LNG storage}} \bullet EF_{\text{LNG storage}}$$

Where:

$E_{transmission\ and\ storage}$ = Total amount of GHG gas emitted due to all relevant natural gas transmission and storage activities

$A_{transmission}$ = Volume of natural gas consumed/Length of transmission pipeline

$EF_{transmission}$ = Emission factor for gas transmitted

$A_{storage}$ = Volume of natural gas consumed

$EF_{storage}$ = Emission factor for gas consumed

$A_{LNG\ import/export}$ = Number of export/import LNG stations

$EF_{LNG\ import/export}$ = Emission factor for LNG imports and exports

$A_{LNG\ storage}$ = Number of storage LNG stations

$EF_{LNG\ storage}$ = Emission factor for LNG storage

TABLE 4.2.4I (NEW)
TIER 1 EMISSION FACTORS FOR GAS TRANSMISSION AND STORAGE SEGMENT, 1.B.2.B.IV

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Gas Transmis-sion and Storage	Transmission: Limited LDAR or less than 50% of centrifugal compressors have dry seals[a]	All	3.36	-20% to +30%	0.23	-20% to +30%	0.05	-100% to +250%	NA	NA	Tonnes/ million cubic meter gas consumption
			4.10	-20% to +30%	0.28	-20% to +30%	0.06	-100% to +250%	NA	NA	Tonnes/ kilometre pipeline
Gas Transmis-sion and Storage	Transmission: Extensive LDAR, and around 50% or more of centrifugal compressors have dry seals[b]	All	1.29	-20% to +30%	0.15	-20% to +30%	0.02	-100% to +250%	NA	NA	Tonnes/ million cubic meter gas consumption
			2.08	-20% to +30%	0.25	-20% to +30%	0.03	-100% to +250%	NA	NA	Tonnes/ kilometre pipeline
Gas Transmis-sion and Storage	Storage: Limited LDAR or most activities occurring with higher- emitting technologies and practices[c]	All	0.67	-20% to +30%	0.06	-20% to +30%	0.0094	-20% to +500%	NA	NA	Tonnes/ million cubic meter gas consumption
Gas Transmis-sion and Storage	Storage: Extensive LDAR and lower-emitting technologies and practices[d]	All	0.29	-20% to +30%	0.04	-20% to +30%	0.0040	-20% to +500%	NA	NA	Tonnes/ million cubic gas consumption
Gas Transmis-sion and Storage	LNG: Import/Export[e]	All	1,660	-20% to +30%	14,687	-20% to +30%	NA	NA	NA	NA	Tonnes/ station

TABLE 4.2.4I (NEW) (CONTINUED)
TIER 1 EMISSION FACTORS FOR GAS TRANSMISSION AND STORAGE SEGMENT, 1.B.2.B.IV

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Gas Transmis-sion and Storage	LNG: Storage[f]	All	22	-20% to +30%	277	-20% to +30%	NA	NA	NA	NA	Tonnes/ station

NA – Not Applicable

b. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), and the Greenhouse Gas Reporting Program (GHGRP) (United States Environmental Protection Agency (EPA) 2017), as applied in the 2018 U.S. GHG Inventory (United States Environmental Protection Agency (EPA) 2018a) to calculate emissions for the year 1992 (when EPA/GRI study was conducted, and when LDAR practices were limited, and most centrifugal compressors had wet seals). NMVOC values were developed from IPCC 2006 GL by calculating a ratio of NMVOC to CH_4 from IPCC 2006, which was then applied to corresponding CH_4 values in this table.

c. Emission factors for CH_4 and CO_2 developed from data reported to the GHGRP (United States Environmental Protection Agency (EPA) 2017), , and from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), as applied in the 2018 U.S. GHG Inventory to calculate emissions for the year 2016 (most recent year of GHGRP data availability, and when LDAR practices were prevalent and most centrifugal compressors had dry seals). NMVOC values were developed from IPCC 2006 GL by calculating a ratio of NMVOC to CH_4 from IPCC 2006, which was then applied to corresponding CH_4 values in this table.

d. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), and the GHGRP (United States Environmental Protection Agency (EPA) 2017), as applied in the 2018 U.S. GHG Inventory to calculate emissions for the year 1992 (when EPA/GRI study was conducted, and when LDAR practices were limited). NMVOC values were developed from IPCC 2006 GL by calculating a ratio of NMVOC to CH_4 from IPCC 2006, which was then applied to corresponding CH_4 values in this table.

e. Emission factors for CH_4 and CO_2 developed from data reported to the GHGRP (United States Environmental Protection Agency (EPA) 2017), (Zimmerle *et al.* 2015), and from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), as applied in the 2018 U.S. GHG Inventory to calculate emissions for the year 2016 (most recent year of GHGRP data availability, when LDAR practices were prevalent). NMVOC values were developed from IPCC 2006 GL by calculating a ratio of NMVOC to CH_4 from IPCC 2006, which was then applied to corresponding CH_4 values in this table.

f. Emission factors for CH_4 and CO_2 developed from GHGRP (United States Environmental Protection Agency (EPA) 2017) data for years 2015 and 2016 (most recent years of data availability). LNG terminal sizes are found in Table 5 of .

g. Emission factors for CH_4 and CO_2 developed from GHGRP (United States Environmental Protection Agency (EPA) 2017) data for years 2015 and 2016 (most recent years of data availability).

1 B 2 b v Distribution

This segment includes fugitive emissions (including leaks, venting, and any flaring) from the distribution of natural gas. Distribution pipelines take the high-pressure gas from the transmission system at “city gate” stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. Emission sources include leaks from pipelines, metering and regulating stations, meters and short-term surface storage.

For natural gas distribution, the factors are presented both in units of tonne per million cubic meter gas consumption, and in tonnes per km pipeline. The length of distribution pipeline is thought to best reflect emissions from distribution, and if pipeline data are available, they should be applied. However, the inventory compiler should assess which activity data are available and which activity data basis best reflects emissions in that segment for that country. The mix of pipeline materials and extent of any leak detection and repair programs in the country should be assessed. Where this information is unknown, or where distribution pipelines are less than 50% plastic, or where there are limited or no leak detection or repair programs, the first set of emission factors for gas distribution should be used (“Less than 50% plastic pipelines, or limited or no leak detection and repair programs”). Where greater than 50% of distribution pipelines are plastic, and leak detection and repair programs are in use, use the second set of emission factors for gas distribution (“Greater than 50% plastic pipelines, and leak detection and repair programs are in use”). As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series. Distribution system methane emissions from biogas are to be calculated here, and can be calculated using the provided emission factors, provided that methane content of the distributed gas is not expected to significantly differ from distributed natural gas. Fugitive emissions of carbon dioxide from biogas distribution are considered to be biogenic and are not reported under 1.B.2.

Short term surface storage means a man-made above-ground storage facilities, for storage of medium-sized quantities of natural gas, help meet and balance rapid fluctuations in demand. Spherical and pipe storage tanks, and other types of low-pressure containers, are used for this purpose.

The composition of town gas differs from natural gas (see explanation in introduction to Chapter 4.2) and therefore emissions are estimated for town gas using distinct emission factors.

For each category/subcategory listed in Table 4.2.4j below that is occurring in the country, compilers must calculate emissions, and sum them according to Equation 4.2.17. It is recognized that not all countries will have all categories and subcategories occurring.

EQUATION 4.2.17 (NEW)
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM GAS DISTRIBUTION

$$E_{distribution} = A_{gas\ distribution} \bullet EF_{gas\ distribution} + A_{surface\ storage} \bullet EF_{surface\ storage} + A_{distribution\ of\ town\ gas} \bullet EF_{distribution\ of\ town\ gas}$$

Table 4.2.4j (New)
Tier 1 Emission factors for Distribution Segment, 1.B.2.b.v

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Gas Distribution	Less than 50% plastic pipelines, or limited or no leak detection and repair programs[a]	All	2.92	-20% to +120%	0.09	-20% to +120%	0.041	-20% to +500%	NA	NA	Tonnes/ million cubic meter gas consumption
			1.17	-20% to +120%	0.03	-20% to +120%	0.016	-20% to +500%	NA	NA	Tonnes/kilometre of pipeline
Gas Distribution	Greater than 50% plastic pipelines, and leak detection and repair programs are in use[b]	All	0.62	-20% to +120%	0.02	-20% to +120%	0.009	-20% to +500%	NA	NA	Tonnes/ million cubic meter gas consumption
			0.23	-20% to +120%	0.01	-20% to +120%	0.003	-20% to +500%	NA	NA	Tonnes/ kilometre of pipeline
Gas Distribution	Short term surface storage[c]	All	5	-50% to 100%	0.034	-50% to 100%	0.125	-70% to 140%	NA	NA	Tonnes/million cubic meter of gas stored
		All	0.003	±100%	2.1E-05	±100%	7.5E-05	-100% to 170%	NA	NA	Tonnes/ million cubic meter gas consumed
Gas Distribution	Town gas distribution: All[d]	All	0.58	±25%	18.3E-03	±25%	NA	NA	NA	NA	Tonnes/ kilometre of pipeline

TABLE 4.2.4J (NEW) (CONTINUED)
TIER 1 EMISSION FACTORS FOR DISTRIBUTION SEGMENT, 1.B.2.B.V

NA – Not Applicable

a. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), as applied in the 2018 U.S. GHG Inventory (United States Environmental Protection Agency (EPA) 2018a) to calculate emissions for the year 1992 (when EPA/GRI study was conducted). NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table.

b. Emission factors for CH_4 and CO_2 developed from data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP) (United States Environmental Protection Agency (EPA) 2017), (Lamb *et al.* 2015), and from EPA/GRI, Methane Emissions from the Natural Gas Industry (Gas Research Institute 1996), as applied in the 2018 U.S. GHG Inventory to calculate emissions for the year 2016 (most recent year of GHGRP data availability). NMVOC values were developed from *IPCC 2006 GL* by calculating a ratio of NMVOC to CH_4 from *IPCC 2006*, which was then applied to corresponding CH_4 values in this table.

c. Short term storage. (Bender & Langer 2012).

d. Mean emission factors for CH_4 and CO_2 from German inventory (German Government 2018) data (1990-1997). Data for the years 1990-1997 were selected because town gas supply was discontinued after 1997 in Germany.

1 B 2 b vi Post-Meter Emissions

This segment includes fugitive emissions beyond gas meters and from natural gas-fueled vehicles. The emission factors for appliances and power plants include leakage emissions beyond gas meters, such as internal piping and the end of pipe appliances (e.g. home heating, water heating, stoves, barbecues). Emissions from start-stop-losses of appliances and combustion of gas are not included in the methodology. If the number of appliances using natural gas is unknown the number of gas meters or the number of house connections should be used instead multiplied by a typical number of appliances (e.g., 2 for countries with heaters and stoves; 1 in warm countries without heaters). The emission factor for natural gas-fueled vehicles include releases from dead volumes during fueling, emptying of gas cylinders of high-pressure interim storage units, for execution of pressure tests and relaxation of residual pressure from vehicles' gas tanks, for pressure tests or decommissioning.

For each category/subcategory listed in Table 4.2.4k below that is occurring in the country, compilers must calculate emissions, and sum them according to Equation 4.2.18. It is recognized that not all countries will have all categories and subcategories occurring.

EQUATION 4.2.18 (NEW)
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM POST-METER LEAKAGE

$$E_{post\text{-}meter\ leakage} = A_{natural\ gas\ vehicles} \bullet EF_{natural\ gas\ vehicles} + A_{natural\ gas\ appliances} \bullet EF_{natural\ gas\ appliances} + A_{natural\ gas\ power\ plants} \bullet EF_{natural\ gas\ power\ plants}$$

Where:

$E_{post\text{-}meter\ leakage}$ = Total amount of GHG gas emitted due to all relevant post-meter leakages of natural gas

$A_{natural\ gas\ vehicles}$ = Volume of natural gas consumed

$EF_{natural\ gas\ vehicles}$ = Emission factor for natural gas-fueled vehicles

$A_{natural\ gas\ appliances}$ = Number of natural gas appliances in commercial and residential sector

$EF_{natural\ gas\ appliances}$ = Emission factor for appliances in commercial and residential sector

$A_{natural\ gas\ power\ plants}$ = Volume of non-residential and commercial gas consumed

$EF_{natural\ gas\ power\ plants}$ = Emission factor for leakages at industrial plants and power stations

TABLE 4.2.4K (NEW)
TIER 1 EMISSION FACTORS FOR POST-METER SEGMENT, 1.B.2.B.VI

Segment	Sub-segment	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of Value)	Value	Uncer-tainty (% of value)	Value	Uncer-tainty (% of value)	
Post-meter	Natural gas-fueled vehicles[a]	All	0.3E-03	-50% to 100%	2.3E-06	-50% to 100%	8E-06	-70% to 140%	NA	NA	Tonnes/ car
Post-meter	Appliances in commercial and residential sector[b]	All	4E-03	±60%	3.3E-05	±60%	0.1E-03	±60%	NA	NA	Tonnes/ appliance
Post-meter	Leakage at industrial plants and power stations[c]	All	0.4	±60%	3.3E-03	±60%	0.01	±60%	NA	NA	Tonnes/million cubic meter Non-residential and commercial gas consumed

NA – Not Applicable

a. Natural Gas vehicles. (Bender & Langer 2012)

b. Medium value of table 4.2.8 of *2006 GL* (g) (appliances) – conversion with density of 0.72 kg/m3, a CO2 content of 0.9% and a NMVOC content of 2.8%

c. Value from *1996 GL* table 1-5-8 (h) (power plants) – conversion with factor 35 MJ/m, a CO2 content of 0.9% and a NMVOC content of 2.8%

1 B 2 b vii Other

Fugitive emissions (including leaks, venting and flaring) from natural gas systems not otherwise accounted for in the above categories. This may include emissions from well blowouts and pipeline ruptures or dig-ins, accidents, and emergency pressure releases. It is *good practice* to quantify and report such emissions as part of category 1.B.2.b.vii whenever possible. There is no Tier 1 method available for such events, which need to be evaluated on a case-by-case basis, often using a combination of emission factors and engineering calculations. An example of calculating emissions during emergency conditions though an engineering calculation approach is given in (American Petroleum Institute (API) 2009). Other examples of quantifying anomalous leak events include CARB's Aliso Canyon report (California Air Resources Board 2016).

1 B 2 b viii Abandoned Gas Wells

Available information on abandoned oil and gas wells do not indicate a clear distinction between abandoned oil and abandoned gas wells regarding practices or emission factors. As such, please refer to the discussion for 1.B.2.a.vii for background and guidance on abandoned oil wells. The emission factors are presented in Table 4.2.4e. In the future, as additional data on this source become available, distinct emission factors for oil and gas may be possible.

TIER 3 AND 2

Emission factors for conducting Tier 3 and Tier 2 assessments are not provided in the IPCC Guidelines due to the large amount of such information and the fact these data are continually being updated to include additional measurement results and to reflect development and penetration of new control technologies and requirements. Rather, the IPCC has developed an Emission Factor Database (EFDB) which will be periodically updated and is available at www.ipcc-nggip.iges.or.jp/EFDB/main.php. In addition, regular reviews of the literature and country-specific data available through inventories of countries with similar circumstances should still be conducted to ensure that the best available factors are being used. The references for the chosen values should be clearly documented. Typically, emission factors are developed and published by environmental agencies, industry associations and academic literature. It may be necessary to develop inventory estimates in consultation with these organizations. For example, the American Petroleum Institute (API) maintains a Compendium of Emissions Estimating Methodologies for the Oil and Gas Industry, most recently updated in 2009. The API Compendium is available at (American Petroleum Institute (API) 2009).

A software tool for estimating greenhouse gas emissions using equations from the API Compendium is available at:

http://ghg.api.org

Guidance for estimating greenhouse gas emissions has also been developed by a number of national oil and gas industry associations. Such documents may be useful supplemental references and often provide tiered source-specific calculation procedures. Guidance on inventory accounting principles as they apply to the oil and gas industry, and boundary definitions is available in the Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions (International Petroleum Industry Environmental Conservation Association (IPIECA) *et al.* 2011).

When selecting emission factors, the chosen values must be valid for the given application and be expressed on the same basis as the activity data. It also may be necessary to apply other types of factors to correct for site and regional differences in operating conditions and design and maintenance practices, for example:

- Composition profiles of gases from particular oil and gas fields to correct for the amount of CH_4, formation CO_2 and other target emissions;
- Annual operating hours to correct for the amount of time a source is in active service;
- Efficiencies of the specific control measures used.

The following are additional matters to consider in choosing emission factors:

- It is important to assess the applicability of the selected factors for the target application to ensure similar or comparable source behaviour and characteristics;
- In the absence of better data, it may sometimes be necessary to apply factors reported for other regions that practice similar levels of emission control and feature comparable types of equipment;
- Where measurements are performed to develop new emission factors, only recognised or defensible test procedures should be applied. The method and quality assurance (QA)/quality control (QC) procedures should be documented, the sampled sources should be representative of typical variations in the overall source population and a statistical analysis should be conducted to establish the 95 percent confidence interval on the average results.

- Whether and how the emission factors may change over time due to changes in technologies or practices.

4.2.2.4 CHOICE OF ACTIVITY DATA

The activity data required to estimate fugitive emissions from oil and gas activities includes production statistics, infrastructure data (e.g., inventories of facilities/installations, process units, pipelines, and equipment components), and reported emissions from spills, accidental releases, and third-party damages. The basic activity data required for each tier and each type of primary source are summarized in Table 4.2.6, Typical Activity Data Requirements for each Assessment Approach by Type of Primary Source Category. Production statistics provided by national bureaux should be used in favour of those available from international bodies, such as the IEA or the UN, due to their generally better reliability and disaggregation. Regional, provincial/state and industry reporting groups may offer even more disaggregation.

TIER 1

The activity data required at the Tier 1 level has been limited to information that may either be obtained directly from typical national oil and gas statistics or easily estimated from this information. Table 4.2.7 below lists the relevant activity data for each of the Tier 1 emission factors presented in Tables 4.2.4 to 4.2.4k, and gives appropriate guidance for obtaining or estimating each of the required activity values.

TIER 2

The activity data required for the standard Tier 2 methodological approach is the same as that required for the Tier 1 approach. If the alternative Tier 2 approach described in Section 4.2.2.2 for crude oil systems is used, then additional, more detailed, information is required including average GOR values, information on the extent of gas conservation and factors for apportioning waste associated gas volumes between venting and flaring. This additional information should be developed based on input from the industry.

TABLE 4.2.6 (UPDATED)
TYPICAL ACTIVITY DATA REQUIREMENTS FOR EACH ASSESSMENT APPROACH FOR FUGITIVE EMISSIONS FROM OIL AND GAS SYSTEMS BY TYPE OF PRIMARY SOURCE

Assessment Tier	Primary Source	Activity Data
1	All	See Table 4.2.7 below.
2	Venting and Flaring from Oil Production	Gas to Oil Ratios Flared and Vented Volumes Conserved Gas Volumes Re-injected Gas Volumes Utilised Gas Volumes Gas Compositions
	All Others	See Table 4.2.7, which is relevant to Tier 2 as well as Tier 1.

TABLE 4.2.6 (UPDATED) (CONTINUED)
TYPICAL ACTIVITY DATA REQUIREMENTS FOR EACH ASSESSMENT APPROACH FOR FUGITIVE EMISSIONS FROM OIL AND GAS SYSTEMS BY TYPE OF PRIMARY SOURCE

Assessment Tier	Primary Source	Activity Data
3	Process Venting/Flaring	Reported Volumes Gas Compositions Proration Factors for Splitting Venting from Flaring
	Storage Losses	Solution Gas Factors Liquid Throughputs Tank Sizes Vapour Compositions
	Equipment Leaks	Facility/Installation Counts by Type Processes Used at Each Facility Equipment Component Schedules by Type of Process Unit Gas/Vapour Compositions
	Gas-Operated Devices	Schedule of Gas-operated Devices by Type of Process Unit Gas Consumption Factors Type of Supply Medium Gas Composition
	Accidental Releases & Third-Party Damages	Incident Reports/Summaries
	Gas Migration to the Surface & Surface Casing Vent Blows	Average Emission Factors & Numbers of Wells
	Drilling	Number of Wells Drilled Reported Vented/Flared Volumes from Drill Stem Tests Typical Emissions from Mud Tanks
	Well Servicing	Tally of Servicing Events by Types
	Pipeline Leaks	Type of Piping Material Length of Pipeline
	Exposed Oils ands/Oil Shale	Exposed Surface Area Average Emission Factors
	Abandoned wells	Number of leaking abandoned wells Total annual methane volumes from abandoned wells

Table 4.2.7 below provides a list of the activity data values used in calculating emissions with a Tier 1 approach. In general, values should be directly referenced from national statistics. Note that not all values present in the table will be needed to calculate emissions. For most calculations, several emission factors are provided to correspond with different activity data options. The inventory compiler should assess which activity data are available and which activity data basis best reflects emissions in that segment for that country.

TABLE 4.2.7 (UPDATED)
GUIDANCE ON OBTAINING THE ACTIVITY DATA VALUES REQUIRED FOR USE IN THE TIER 1 APPROACH TO ESTIMATE FUGITIVE EMISSIONS FROM OIL AND GAS SYSTEMS

Segment	Sub-segment	Activity Data Values
Oil Exploration 1B.2.a.i	Onshore: Unconventional without flaring or recovery	• Unconventional onshore oil wells drilled in a year, without flaring or recovery, or • Total unconventional onshore oil well population where exploration occurs without flaring or recovery, or • Thousand cubic meters onshore unconventional onshore oil production where exploration occurs without flaring or recovery
	Onshore: Unconventional with flaring or recovery	• Unconventional onshore oil wells drilled in a year, with flaring or recovery, or • Total unconventional onshore oil well population where exploration occurs with flaring or recovery, or • Thousand cubic meters onshore unconventional oil production where exploration occurs with flaring or recovery
	Onshore: Conventional	• Onshore conventional oil wells drilled in a year, or • Total conventional onshore oil well population, or • Thousand cubic meters onshore conventional oil production
Oil Production 1.B.2.a.ii	Onshore: Most activities occurring with higher- emitting technologies and practices[a]	• Thousand cubic meters onshore oil production (where production occurs with higher-emitting technologies and practices), or • Active oil wells (where production occurs with higher-emitting technologies and practices)
	Onshore: Most activities occurring with lower-emitting technologies and practices[b]	• Thousand cubic meters onshore oil production (where production occurs with lower-emitting technologies and practices), or • Active oil wells (where production occurs with lower-emitting technologies and practices)
	Oil Sands Mining and Ore Processing[c]	• Thousand cubic meters crude bitumen production from surface mining
	Oil Sands Upgrading[c]	• Thousand cubic meters synthetic crude oil production
	Offshore: All[d]	• Thousand cubic meters offshore oil production
	Oil Upgrading	• Thousand cubic meters oil upgraded
Oil Transport 1.B.2.a.iii	Pipelines	• Thousand cubic meters oil transported by pipeline
	Tanker Trucks and Rail Cars	• Thousand cubic meters oil transported by Tanker Truck or rail car
	Tanks	• Thousand cubic meters crude oil feed
	Loading of Off-shore Production on Tanker Ships without VRU	• Thousand cubic meters oil transported by Tanker Ship without VRU
	Loading of Off-shore Production on Tanker Ships with VRU	• Thousand cubic meters oil transported by Tanker Ship with VRU

TABLE 4.2.7 (UPDATED) (CONTINUED)
GUIDANCE ON OBTAINING THE ACTIVITY DATA VALUES REQUIRED FOR USE IN THE TIER 1 APPROACH TO ESTIMATE FUGITIVE EMISSIONS FROM OIL AND GAS SYSTEMS

Segment	Sub-segment	Activity Data Values
Oil Refining 1.B.2.a.iv	All	• Thousand cubic meters oil refined.
Refined Product Distribution 1.B.2.a.v	Gasoline	• Thousand cubic meters product distributed.
	Other	• Thousand cubic meters (e.g. diesel, aviation fuel, jet kerosene) transported.
Other 1.B.2.a.vi	All	
Abandoned wells 1.B.2.a.vii	All	• Number of abandoned wells, onshore and offshore, plugged and unplugged.
Gas Exploration 1.B.2.b.i	Onshore: Unconventional without flaring or gas capture	• Unconventional onshore gas wells drilled in a year, without flaring or recovery, or • Total unconventional onshore gas well population where exploration occurs without flaring or recovery, or • Million cubic meters onshore unconventional onshore gas production where exploration occurs without flaring or recovery
	Onshore: Unconventional with flaring or gas capture	• Unconventional onshore gas wells drilled in a year, with flaring or recovery, or • Total unconventional onshore gas well population where exploration occurs with flaring or recovery, or • Million cubic meters onshore unconventional gas production where exploration occurs with flaring or recovery
	Onshore: Conventional	• Onshore conventional gas wells drilled in a year, or • Total conventional onshore gas well population, or • Million cubic meters onshore conventional gas production
Gas Production 1.B.2.b.ii	Onshore: Most activities occurring with higher- emitting technologies and practices[a]	• Million cubic meters onshore gas production (where production occurs with higher-emitting technologies and practices), or • Active gas wells (where production occurs with higher-emitting technologies and practices)
	Onshore: Most activities occurring with lower-emitting technologies and practices[b]	• Million cubic meters onshore gas production (where production occurs with lower-emitting technologies and practices), or • Active gas wells (where production occurs with lower-emitting technologies and practices)
	Onshore Production – Coal Bed Methane	• Million cubic meters onshore CBM production
	Gathering	• Million cubic meters onshore gas production
	Offshore production	• Million cubic meters offshore gas production

TABLE 4.2.7 (UPDATED) (CONTINUED)
GUIDANCE ON OBTAINING THE ACTIVITY DATA VALUES REQUIRED FOR USE IN THE TIER 1 APPROACH TO ESTIMATE FUGITIVE EMISSIONS FROM OIL AND GAS SYSTEMS

Segment	Sub-segment	Activity Data Values
Gas Processing 1.B.2.b.iii	Without LDAR, less than 50% of centrifugal compressors have dry seals	• Million cubic meters gas processed (where gas is processed without LDAR, and less than 50% of centrifugal compressors have dry seals), or • Million cubic meters gas produced (where gas is processed without LDAR, and less than 50% of centrifugal compressors have dry seals)
	With LDAR, 50% or more of centrifugal compressors have dry seals	• Million cubic meters gas processed (where gas is processed without LDAR, and 50% or more of centrifugal compressors have dry seals), or • Million cubic meters gas produced (where gas is processed without LDAR, and 50% or more of centrifugal compressors have dry seals)
	Sour Gas Plants	• Million cubic meters sour gas processed
Gas Transmission & Storage 1.B.2.b.iv	Transmission: Most activities occurring with higher- emitting technologies and practices	• Kilometre of transmission pipeline (where transmission occurs with higher-emitting technologies and practices), or • Million cubic meters of gas consumption pipeline (where transmission occurs with higher-emitting technologies and practices)
	Transmission: Most activities occurring with lower-emitting technologies and practices	• Kilometre of transmission pipeline (where transmission occurs with lower-emitting technologies and practices), or • Million cubic meters of gas consumption pipeline (where transmission occurs with lower-emitting technologies and practices)
	Storage: Most activities occurring with higher- emitting technologies and practices	• Million cubic meters of gas consumption (where storage occurs with higher-emitting technologies and practices)
	Storage: Most activities occurring with lower-emitting technologies and practices	• Million cubic meters of gas consumption (where storage occurs with lower-emitting technologies and practices)
	LNG Import/Export	• Number of LNG Import/Export stations
	LNG Storage	• Number of LNG Storage stations
Gas Distribution 1.B.2.b.v	Less than 50% plastic pipelines, and limited or no leak detection and repair programs	• Kilometre of distribution pipeline (where distribution occurs with less than 50% plastic pipelines, and limited or no leak detection and repair programs), or • Million cubic meters gas consumption
	Greater than 50% plastic pipelines, and leak detection and repair programs are in use	• Kilometre of distribution pipeline (where distribution occurs with greater than 50% plastic pipelines, and leak detection and repair program), or • Million cubic meters gas consumption
	Short term surface storage	• Million cubic meters of gas stored in short term surface storage
	Distribution of town gas	• Kilometre of pipeline distributing town gas

TABLE 4.2.7 (UPDATED) (CONTINUED)
GUIDANCE ON OBTAINING THE ACTIVITY DATA VALUES REQUIRED FOR USE IN THE TIER 1 APPROACH TO ESTIMATE FUGITIVE EMISSIONS FROM OIL AND GAS SYSTEMS

Segment	Sub-segment	Activity Data Values
Gas Post-Meter 1.B.2.b.vi	Natural Gas Vehicles	• Total natural gas vehicles
	Appliances in commercial and residential sector	• Total appliances
	Industrial plants and power plants	• Million cubic meters non-residential and commercial gas consumed
Other 1.B.2.b.vii	All	
Abandoned wells 1.B.2.b.viii	All	• Number of abandoned wells, onshore and offshore, plugged and unplugged

TIER 3

Approaches and level of disaggregation for Tier 3 estimates can vary widely. In the case of Tier 3, Table 4.2.6 lists examples of some activity data that might be used for Tier 3 estimates.

Specific matters to consider in compiling the detailed activity data required for use in a Tier 3 approach include the following:

- Production statistics should be disaggregated to capture changes in throughputs (e.g., due to imports, exports, reprocessing, withdrawals, etc.) in progressing through oil and gas systems.
- Production statistics provided by national bureaux should be used in favour of those available from international bodies, such as the IEA or the UN, due to their generally better reliability and disaggregation. Regional, provincial/state and industry reporting groups may offer even more disaggregation.
- Production data used in estimating fugitive emissions should be corrected, where applicable, to account for any net imports or exports. It is possible that import and export data may be available for a country while production data are not; however, it is unlikely that the opposite would be true
- Where coalbed methane is produced into a natural gas gathering system, any associated fugitive emissions should be reported under the appropriate natural gas exploration and production categories. This will occur by default since the produced gas becomes a commodity once it enters the gas gathering system and automatically gets accounted for the same way gas from any other well does when it enters the gathering system. The fact that gas is coming from a coal formation would only be discernible at a very disaggregated level. Where a coal formation is degassed for the purposes of coal exploration or coal mining and handling, the associated emissions should be allocated to the coal sector under the appropriate section of IPCC category 1.B.1.
- Vented and flared volumes from oil and gas statistics may be highly suspect since these values are usually estimates and not based on actual measurements. Additionally, the values are often aggregated and simply reported as flared volumes. Operating practices of each segment of the industry should be reviewed with industry representatives to determine if the reported volumes are actually vented or flared, or to develop appropriate apportioning of venting relative to flaring. Audits or reviews of each industry segment should also be conducted to determine if all vented and flared volumes are actually reported (for example, solution gas emissions from storage tanks and treaters, emergency flaring/venting, leakage into vent/flare systems, and blowdown and purging volumes may not necessarily be accounted for).
- Infrastructure data are more difficult to obtain than production statistics. Information concerning the numbers and types of major facilities and the types of processes used at these facilities may often be available from regulatory agencies and industry groups, or directly from the actual companies.
- Information on minor facilities (e.g., numbers of field dehydrators and field compressors) usually is not available, even from oil and gas companies. Consequently, assumptions must be made, based on local design

practices, to estimate the numbers of these facilities. This may require some fieldwork to develop appropriate estimation factors or correlations.

- Many companies use computerised inspection-and-maintenance information management systems. These systems can be a very reliable means of counting major equipment units (e.g., compressor units, process heaters and boilers, etc.) at selected facilities. Also, some departments within a company may maintain databases of certain types of equipment or facilities for various internal reasons (e.g., tax accounting, production accounting, insurance records, quality control programmes, safety auditing, license renewals, etc.). Efforts should be made to identify these potentially useful sources of information.
- Component counts by type of process unit may vary dramatically between facilities and countries due to differences in design and operating practices. Thus, while initially it may be appropriate to use values reported in the general literature, countries should strive to develop their own values.
- Use of consistent terminology and clear definitions is critical in developing counts of facilities and equipment components, and to allow any meaningful comparisons of the results with others.
- Some production statistics may be reported in units of energy (based on their heating value) and will need to be converted to a volume basis, or vice versa, for application of the available emission factors. Typically, where production values are expressed in units of energy, it is in terms of the gross (or higher) heating value of the product. However, where emission factors are expressed on an energy basis it is normally in terms of the net (or lower) heating value of the product. To convert from energy data on a GCV basis to a NCV basis, the International Energy Agency assumes a difference of 5 percent for oil and 10 percent for natural gas. Individual natural gas streams that are either very rich or high in impurities may differ from these average values. Emission factors and activity data must be consistent with each other.
- Oil and gas imports and exports will change the activity levels in corresponding downstream portions of these systems.
- Production activities will tend to be the major contributor to fugitive emissions from oil and gas activities in countries with low import volumes relative to consumption and export volumes. Gas transmission and distribution and petroleum refining will tend to be the major contributors to these emissions in countries with high relative import volumes. Overall, net importers will tend to have lower specific emissions than net exporters.

4.2.2.5 COMPLETENESS

Completeness is a significant issue in developing an inventory of fugitive emissions for the oil and gas industry. It can be addressed through direct comparisons with other countries and, for refined inventories, through comparisons between individual companies in the same industry segment and subcategory. This requires the use of consistent definitions and classification schemes. For example, in Canada, the upstream petroleum industry has adopted a benchmarking scheme that compares the emission inventory results of individual companies in terms of production-energy intensity and production-carbon intensity. Such benchmarking allows companies to assess their relative environmental performance. It also flags, at a high level, anomalies or possible errors that should be investigated and resolved.

The Tier 1 EF and their associated uncertainty ranges presented in Tables 4.2.3 to 4.2.13 may be used to assess reasonableness of Tier 2 and Tier 3 factors. If emissions from specific segments are appreciably less than the low end or greater than the high end of the uncertainty range, this should be explained; otherwise, it may be an indication of possible missed or double counted contributions, respectively.

Where emission inventories are developed based on a compilation of individual company-level inventories, care should be taken to ensure that all companies are included. Appropriate extrapolations may be needed to account for any non-reporting companies.

Smaller individual sources, when aggregated nationally over the course of a year, may often be significant total contributors. Therefore, *good practice* is not to disregard them. Once a thorough assessment has been done, a basis exists for simplifying the approach and better allocating resources in the future to best reduce uncertainties in the results.

Where a country has estimated its fugitive emissions from part or all of its oil and natural gas system based on a roll-up of estimates reported by individual oil and gas companies, it is *good practice* to document the steps taken to ensure that these results are complete, transparent and consistent across the time series. Corrections made to account for companies or facilities that did not report, and measures taken to avoid missed or double counting (particularly where ownership changes have occurred) and to assess uncertainties should be highlighted.

Where Tier 2 or Tier 3 approaches are used to calculate a subset of emissions (e.g. flaring), care should be taken to ensure that all remaining emissions (e.g. venting and fugitives) are accounted (e.g. using disaggregated Tier 1 factors in Appendix 4A.2).

4.2.2.6 DEVELOPING CONSISTENT TIME SERIES

Ideally, emission estimates will be prepared for the base year and subsequent years using the same method. The aim is to have emission estimates across the time series reflect true trends in greenhouse gas emissions. Emission or control factors that change over time (e.g., due to changes in source demographics or the penetration of control technologies) should be regularly updated and, each time, only applied to the period for which they are valid. For, example, if an emission control device is retrofit to a source then a new emission factor will apply to that source from then onwards; however, the previously applied emission factor reflecting conditions before the retrofit should still be applied for all previous years in the time series. If an emission factor has been refined through further testing and now reflects a better understanding of the source or source category, then all previous estimates should be updated to reflect the use of the improved factor and be reported in a transparent manner.

Tier 1 emission factors provided in Tables 4.2.3 to 4.2.13 are technology/practice-specific to the extent possible. A country should assess which technologies and practices are generally in place in the country and apply the corresponding emission factor. As technologies and practices change over time, it is possible that a country will use one EF in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series.

Where some historical data are missing, it should still be possible to use source-specific measurement results combined with back-casting techniques to establish an acceptable relationship between emissions and activity data in the base year. Approaches for doing this will depend on the specific situation, and are discussed in general terms in Volume 1 Chapter 5 of the *2006 Guidelines*.

If emission estimates are developed based on a roll-up of individual company estimates, greater effort will be required to maintain time series consistency, particularly where frequent facility ownership changes occur and different methodologies and emission factors are applied by each new owner without also carrying these changes back through the time series.

4.2.2.7 UNCERTAINTY ASSESSMENT

Sources of error that may occur include the following:

- Measurement errors;
- Extrapolation errors;
- Inherent uncertainties of the selected estimation techniques;
- Missing or incomplete information regarding the source population and activity data;
- Poor understanding of temporal and seasonal variations in the sources;
- Over or under accounting due to confusion or inconsistencies in category divisions and source definitions;
- Misapplication of activity data or emission factors (including due to incomplete information for assigning technology- and practice-specific emission factors);
- Errors in reported activity data;
- Missed accounting of intermediate transfer operations and reprocessing activities (for example, re-treating of slop oil, treating of foreign oil receipts and repeated dehydration of gas streams: in the field, at the plant, and then following storage);
- Differences in the effectiveness of control devices, potential deterioration of their performance over time and missed accounting of control measures.

Guidance regarding the assessment of uncertainties in emission factors and activity data are presented in the subsections below.

4.2.2.7.1 EMISSION FACTOR UNCERTAINTIES

The uncertainty in an emission factor will depend both on the accuracy of the measurements upon which it is based and the degree to which these results reflect the average behaviour of the target source population, including whether the measurements capture any high-emitting subpopulations (e.g., malfunctions) and episodic sources and whether these have been incorporated into the average factors in a way that does not over- or under-estimate total emissions. Accordingly, emission factors developed based on data measured in one country may have one set of uncertainties when the factors are applied in that country and another set of uncertainties when they are applied similarly in a different country. Thus, while it is difficult to establish one set of uncertainties that will always apply, a set of default values has been provided for the default factors provided in Tables 4.2.3 through 4.2.13. These uncertainties are estimated based on expert judgement and reflect the level of uncertainty that may be expected when the corresponding emission factors are used to develop emission estimates at the national level. Use of the presented factors to estimate emissions from individual facilities or sources would be expected to result in much greater uncertainties.

4.2.2.7.2 ACTIVITY DATA UNCERTAINTIES

The percentages cited in this section are based on expert judgement and aim to approximate the 95 percent confidence interval around the central estimate. Gas compositions are usually accurate to within ±5 percent on individual components. Flow rates typically have errors of ±3 percent or less for sales volumes and ±15 percent or more for other volumes. Production statistics or disposition analyses may not agree between different reporting agencies even though they are based on the same original measurement results (e.g. due to possible differences in terminology and potential errors in summarising these data). These discrepancies may be used as an indication of the uncertainty in the data. Additional uncertainty will exist if there is any inherent bias in the original measurement results (for example, sales meters are often designed to err in favour of the customer, and liquid handling systems will have a negative bias due to evaporation losses). Random metering and accounting errors may be assumed to be negligible when aggregated over the industry.

Where available, counts of major facilities (e.g., gas plants, refineries and transmission compressor stations) may be known with little error (e.g., less than 5 percent). Where errors in these counts occur it is usually due to some uncertainties regarding the number of new facilities built and old facilities decommissioned during the time period.

Counts of well site facilities, minor field installations and gas gathering compressor stations, as well as the type and amount of equipment at each site, will be much less accurately known, if known at all (e.g., at least ±25 percent uncertainty or more).

Estimates of emission reductions from individual control actions may be accurate to within a few percent to ±25 percent depending on the number of subsystems or sources considered.

4.2.3 Inventory Quality Assurance/Quality Control (QA/QC)

It is *good practice* to conduct quality control checks as outlined in Volume 1 Chapter 6 of the *2006 IPCC Guidelines*, Tier 1 General Inventory Level QC Procedures, and expert review of the emission estimates. Additional quality control checks, as outlined in Volume 1 Chapter 5 of the *2006 IPCC Guidelines*, and quality assurance procedures may also be applicable, particularly if higher tier methods are used to determine emissions from this source category. Inventory compilers are encouraged to use higher tier QA/QC for *key categories* as identified in Volume 1 Chapter 4 of the *2006 IPCC Guidelines*.

In addition to the guidance in Volume 1 Chapter 6 of the *2006 IPCC Guidelines*, specific procedures of relevance to this source category are outlined below.

REVIEW OF DIRECT EMISSION MEASUREMENTS

If direct measurements are used to develop country-specific emission factors, the inventory compiler should establish whether measurements at the sites were made according to recognised standard methods. If the measurement practices fail this criterion, then the use of these emissions data should be carefully evaluated, estimates reconsidered and qualifications documented. The compiler should also assess key background information in the study, such as, what activities are occurring and what equipment is in place (including controls) at the time of measurement and whether the measurements are representative of average conditions for that activity and may be applied as an average factor, or if it should be adjusted for different operating practices, etc. The compiler should confirm that the categorizations (e.g. for equipment and practices) used in the study are the same as used in the inventory, and should make adjustments if not. The national representativeness of the factors should also be assessed. As applicable, the attribution of measured emissions to the specific equipment or broader category should also be assessed.

ACTIVITY DATA CHECK

Several different types of activity data may be required for this source category, depending on which methodological tier is used to estimate the emissions. Where activity data are available from multiple sources (i.e.

from national statistics and industry organisations) these data sets should be checked against each other to assess reasonableness. Significant differences in data should be explained and documented. Trends in the main emission drivers and activity data over time should be checked and any anomalies investigated.

EXTERNAL REVIEW AND STAKEHOLDER INVOLVEMENT

Emission inventories for large, complex oil and gas industries may be susceptible to errors due to missed or unaccounted for sources, or due to customization of average emission factors taken from a data source that represents estimates from another country or region with operating characteristics different from those in the country where the emission factor is being applied. To minimise such errors, it is important to obtain active involvement of industry and other technical experts in the preparation and refinement of these inventories. This will be especially important in the selection of appropriate technology- and practice-specific emission factors.

4.2.4 Reporting and Documentation

It is *good practice* to document and archive all information required to produce the national emissions inventory estimates, as outlined in Volume 1 Chapter 8 of the *2006 Guidelines*.

It may not be practical to include all supporting documentation in the inventory report. However, at a minimum, the inventory report should include summaries of the methods used and references to source data such that the reported emissions estimates are transparent and the steps in their calculation may be retraced. For segments where a technology- or practice-specific Tier 1 emission factor is used, the rationale for selecting that factor and the method for applying the factors over the time series must be clearly documented. It is expected that many countries will use a combination of methodological tiers to evaluate the amount of fugitive greenhouse gas emissions from the different parts of their oil and natural gas systems. The specific choices should reflect the relative importance of the different subcategories and the availability of the data and resources needed to support the corresponding calculations. Table 4.2.9 is a sample template, with some example data entries, that may be used to conveniently summarize the applied methodologies and sources of emission factors and activity data. Tier 1 EF are inclusive of venting, flaring, and leak emissions. For calculations, compilers may separate their emissions into the separate categories of venting, flaring and leaks if data are available. Emissions reported for each segment should be inclusive of venting, flaring, and leak emissions (i.e., should represent the total emissions for that segment). If a compiler choses to report disaggregated data on venting and flaring, they may do so as information items.

Since emission factors and estimation procedures are continually being improved and refined, it is possible for changes in reported emissions to occur without any real changes in actual emissions. Accordingly, the basis for any changes in results between inventory recalculations should be clearly discussed and those due strictly to changes in methods and factors should be highlighted.

The issue of confidential business information will vary from region to region depending on the number of firms in the market and the nature of the business. The significance of this issue tends to increase in progressing downstream through the oil and gas industry. A common means to address such issues where they do arise is to aggregate the data using a reputable independent third party.

The above reporting and documentation guidance is applicable to all methodological choices. Where Tier 3 approaches are employed, it is important to ensure that either the applied procedures are detailed in the inventory report or that available references for these procedures are cited since the IPCC Guidelines do not describe a standard Tier 3 approach for the oil and gas sector. There is a wide range in what potentially may be classified as a Tier 3 approach, and correspondingly, in the amount of uncertainty in the results. If available, summary performance and activity indicators should be reported to help put the results in perspective (e.g. total production levels and transportation distances, net imports and exports, and specific energy, carbon and emission intensities). Reported emission results should also include a trend analysis to show changes in emissions, activity data and emission intensities (i.e., average emissions per unit of activity indicator) over time. The expected accuracy of the results should be stated and the areas of greatest uncertainty clearly noted.

The current trend by some government agencies and industry associations is to develop detailed methodology manuals and reporting formats for specific segments and subcategories of the industry. This is perhaps the most practical means of maintaining, documenting and disseminating the subject information. However, all such initiatives must conform to the common framework established in the IPCC Guidelines so that the emission results can be compared across countries.

TABLE 4.2.9 (UPDATED)
FORMAT FOR SUMMARIZING THE APPLIED METHODOLOGY AND BASIS FOR ESTIMATED EMISSIONS FROM OIL AND NATURAL GAS SYSTEMS SHOWING SAMPLE ENTRIES

IPCC Code	Category, Sub-category or Segment	Sub-segment (if applicable)	Source Type (all, vent, flare, leak)	Method	Activity Data			Emission Factors			
					Type	Basis	Year	Basis/Reference[10]			Date Country Specific Values Updated
								CH_4	CO_2	N_2O	
1.B.2	Oil and Natural Gas										
1.B.2.a	Oil										
1.B.2.a.i	Exploration										
1.B.2.a.ii	Production and Upgrading										
1.B.2.a.iii	Transport										
1.B.2.a.iv	Refining										
1.B.2.a.v	Distribution of oil products										
1.B.2.a.vi	Other										
1.B.2.a.vii	Abandoned Wells										
1.B.2.b	Natural Gas										

[10] Include here information on basis for selecting technology/practice-specific factors, as applicable.

TABLE 4.2.9 (UPDATED) (CONTINUED)
FORMAT FOR SUMMARIZING THE APPLIED METHODOLOGY AND BASIS FOR ESTIMATED EMISSIONS FROM OIL AND NATURAL GAS SYSTEMS SHOWING SAMPLE ENTRIES

IPCC Code	Category, Sub-category or Segment	Sub-segment (if applicable)	Source Type (all, vent, flare, leak)	Method	Activity Data			Emission Factors			
								Basis/Reference			Date
					Type	Basis	Year	CH_4	CO_2	N_2O	Country Specific Values Updated
1.B.2.b.i	Exploration										
1.B.2.b.ii	Production	Gas Production	All	Tier 1	Throughput	National Statistics	2005	D	D	D	---
1.B.2.b.iii	Processing	All	All	Tier 1	Throughput	National Statistics	2005	D	D	D	---
1.B.2.b.iv	Transmission and Storage	Gas Transmission	All	Tier 2	Number of facilities	Industry Survey	2005	CS	CS	-----	2005
1.B.2.b.v	Distribution										
1.B.2.b.vi	Post-Meter										
1.B.2.b.vii	Other										
1.B.2.b.viii	Abandoned Wells										
1.B.3	Other emissions from Energy Production										

D – IPCC Default Emission Factors
CS – Country-Specific Emission Factors
EFDB – IPCC Emission Factor Database

4.3 FUGITIVE EMISSIONS FROM FUEL TRANSFORMATION

Fuel transformation occurs when energy products are transformed into other energy products more suitable for their end use. Transformation occurs by physical or chemical conversion into a product whose intrinsic properties differ from those of the original product (e.g. charcoal production; or coke oven carbonization of coal); or by aggregation and blending of products, sometimes involving a change of the physical shape (e.g. briquetting of brown coal) (UNSD, 2018).

4.3.1 Overview and description of sources

This section is a new guidance. It clarifies how fugitive emissions from fuel transformation should be estimated. Emissions from these fuel transformation activities link to the Energy, IPPU and AFOLU sectors and cross references are provided to the relevant sections in the guidelines. Inventory compilers should ensure all emissions from specific fuel transformation activities are captured in their inventories but are not double counted.

Fugitive emissions from two groups of transformation process have been included in this section:

- **Solid to solid transformation processes** (charcoal production; coke production). The organisation of this section is based on the transformation of the physical state of the fuel;
- **Gasification transformation processes** (coal to liquids; gas to liquids). The organisation of this section is based on the technologies used.

The boundaries for all these transformation activities are the respective transformation process boundaries, and fugitive emissions in upstream and downstream supply chains are to be estimated using appropriate methodologies elsewhere in these guidelines, including in other volumes.

Other transformation processes (e.g. patent fuel, coal briquetting, town gas production) are not explicitly addressed. If parties have country specific methodologies available, they may report emissions in these categories. Hydrogen production is considered in Volume 3, Chapter 3.11; refineries are considered in Chapter 4.2 in this volume.

TABLE 4.3.1 (NEW)
ESTIMATION AND REPORTING OF FUGITIVE EMISSIONS FROM FUEL TRANSFORMATION

Fuel transformation	**Methods for estimating fugitive emissions from the transformation of this fuel are set out in the following section of the Guidelines**	**Fugitive emissions from the transformation of this fuel should be reported under the following category**
Solid to solid transformation processes		
Charcoal and biochar production	4.3.2.1	CH_4, N_2O in 1.B.1.c.i Non-fossil CO_2 as a memo item "CO_2 emissions from biomass"
Coke production (including flaring)	4.3.2.1	CH_4, N_2O in 1.B.1.c.ii
Wood pellet production	Appendix 4a.2	CH_4, N_2O in 1.B.1.c.iii CO_2 as a memo item "CO_2 emissions from biomass"
Gasification transformation processes		
Coal to liquids	4.3.2.2	CH_4, N_2O in 1.B.1.c.iv
Gas to liquids	4.3.2.2	CH_4, N_2O in 1.B.1.c.iv
Biomass to liquids	Appendix 4a.2	CH_4, N_2O in 1.B.3
Biomass to gas	Appendix 4a.2	CH_4, N_2O in 1.B.3

Notes:

Further details about reporting of emissions from coke production are given in Table 4.3.4

4.3.2 Methodological issues

4.3.2.1 SOLID TO SOLID TRANSFORMATION PROCESSES

CHARCOAL AND BIOCHAR PRODUCTION

About half the wood extracted worldwide from forests is used to produce energy, mostly for cooking and heating. Some of the wood is used to make charcoal. The share of energy use from harvested wood is as high as 90 percent in Africa and more than 60 percent in Asia. An estimated 17 per cent of wood extracted from forests was converted to charcoal (FAO, 2016), and most of the remainder was used in the form of fuelwood. Charcoal production can be on very small scales (domestic) to larger scales (industrial), is normally poorly regulated with little or no emission control. Emissions are due largely to unsustainable forest management, inefficient charcoal manufacture and woodfuel combustion (FAO, 2017; AFREA, 2011). Of these sources, the solid to solid transformation process covers emission from inefficient charcoal manufacture.

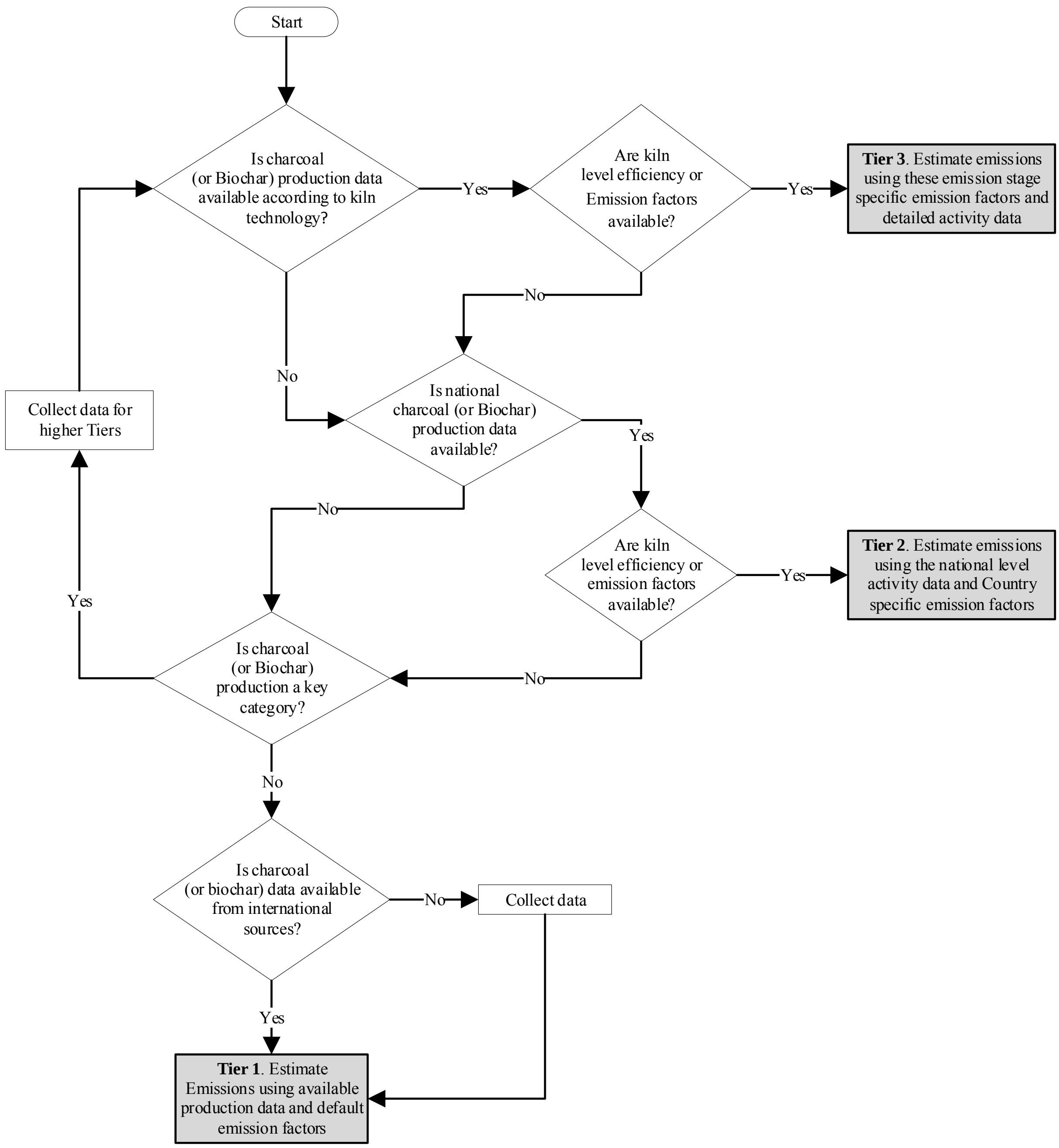
Charcoal is produced by the carbonization of wood. Carbonization of fuel is the thermal decomposition in the absence of oxygen at a temperature above 300°C. The carbonization of wood produces charcoal, volatile compounds and a range of gases. The gases produced include direct greenhouse gases (CO_2, CH_4 and N_2O), indirect greenhouse gases (CO) and other gases, including H_2. Emissions of biogenic CO_2 from charcoal production are reported here as an information item, and are covered under Agriculture, Land Use Change and Forestry (AFOLU). Fugitive emissions of CH_4 and N_2O are reported here.

Some biochar is also produced from harvested wood, which is mainly applied in soils (please refer to AFOLU Chapter Section 4.2.2.3.1 for details) and also some biochar produced could be used for making biochar briquettes that are used for energy purposes. The fugitive CH_4 and N_2O emissions from production of biochar to be used for energy purposes would be reported in the Energy volume, while those emitted during the biochar produced that is applied in agriculture sector would be estimated and reported following the methodologies set out in the AFOLU volume.

CHOICE OF METHODS, DECISION TREES, TIERS

Figure 4.3.1 shows the decision tree for estimating fugitive emissions from charcoal production activities. For countries with kiln-level charcoal production data, or kiln type data, and who have kiln efficiency or emission factor data available, a Tier 3 estimation could be applied. For countries where country level charcoal production data is available, a country specific EF may be estimated and applied in a Tier 2 approach. However, if fugitive emissions from fuel transformation are a key category, and charcoal production is a significant source within that category, estimate emissions using higher tiers. If fugitive emissions are not a significant source, then emissions can be estimated using a Tier 1 method. A similar approach should to be followed for biochar production.

Figure 4.3.1 (New) Decision tree for Charcoal (and biochar) production



Tier 1

The general form of the equation for estimating emissions for Tier 1 approach, based on charcoal production activity data is given by Equation 4.3.1 below.

EQUATION 4.3.1 (NEW)
FUGITIVE GHG EMISSIONS FROM CHARCOAL (OR BIOCHAR) PRODUCTION ON ANNUAL BASIS

$$Emissions_{GHG,\ charcoal\ (or\ biochar)\ produced} = Charcoal\ (or\ biochar)\ produced \bullet Emission\ Factor_{GHG}$$

Where:

$Emissions_{GHG,\ charcoal\ (or\ biochar)\ produced}$ = emissions of a given GHG (g GHG)

Charcoal (or biochar) produced = amount of charcoal (or biochar) produced (kg)

$Emission\ Factor_{GHG}$ = emission factor GHG (kg GHG/unit of charcoal (or biochar) produced) (g GHG / kg charcoal (or biochar))

Tier 1 emission factors are given in Table 4.3.2.

Inventory compliers should note that compressed lignite briquettes might be added to charcoal, and compilers could check to see if this occurs and the extent to which it occurs. If lignite briquettes are manufactured, fugitive emissions from the manufacture might occur. These emissions should be estimated if country specific emission factors are available. Default emission factors are not available for this source.

Tier 2

The Tier 2 approach uses Equation 4.3.1, but inventory compilers should use country specific EFs.

CHOICE OF EMISSION FACTOR

Table 4.3.2 provides default emission factors calculated as median from various studies and the lower limit and upper limits of charcoal production. Kilns with lower efficiency tend to have a lower emission factor, and vice versa.

Default emission factors for fugitive emissions from lignite briquette production are not available.

TABLE 4.3.2 (NEW)
DEFAULT EMISSION FACTORS FOR CHARCOAL AND BIOCHAR PRODUCTION
(g GHG / kg of charcoal (or biochar) produced)

Gas	Default Emission Factor	Uncertainty (% of value)
Charcoal production [a]		
CO_2 [a]	1,570	-38% to +60%
CH_4	40.3	-68% to +121%
N_2O	0.08	-75% to +163%
CO	220	-52% to +53%
NOx	0.07	±57%
Biochar production [b]		
CO_2 [a]	4,300	±40%
CH_4	30	-100% to +200%
NOx	0.4	±75%
CO	54	±65%

Notes:

Bailis (2009); Taccini (2010); Chidumayo, et al, (2013); Müller, et al, (2011); Pennise et al. (2001); Smith et al. (1999); UNDP (2013)

[a] CO_2 emissions are reported as memo items since carbon released from charcoal (or biochar) production is biogenic in origin

[b] For flame curtain biochar kilns. Source of data: Cornelissen *et al*, 2016

CHOICE OF ACTIVITY DATA

Preference must be given to sourcing accurate charcoal production data. Charcoal production might be available in national energy balances. The quantities of charcoal produced might be recorded by statistical agencies, and could be estimated from the weight or volume of wood used to make charcoal or biochar. But, production may not be solely for domestic purposes, and some charcoal produced might be exported. Total charcoal production can be estimated by measuring the charcoal produced in each kiln countrywide each year. Measurement is done by weighing the bags of charcoal produced at each site. If gravimetric production activity is not available, quantities of charcoal produced can be approximately estimated from the product of the number of charcoal bags filled assuming the weight of each bag is known. Estimates of production made in this way should not be used for an inventory, but could be used to help verify production data from other sources. A similar approach can be followed for biochar production.

If no country specific charcoal production data are available, wood charcoal production according to country maybe available at http://www.fao.org/faostat/.

UNCERTAINTY ASSESSMENT

The uncertainty associated with charcoal (or biochar) production is high as the use of this fuel is typically not accurately recorded at national level, and, most of the traditional charcoal (or biochar) makers do not measure the quantities of charcoal produced. Uncertainties associated with the charcoal production data might be available from statistical data. If such data are not available, then expert elicitation and expert judgement can be used. The uncertainties associated with the emission factors are very high. The emission factors depend on the type of kiln and corresponding efficiency. Since most of the charcoal (or biochar) is produced by traditional mound methods, which are not standardized, the emission factors will necessarily be highly uncertain. Emission factors are not available by kiln type.

Table 4.3.3 provides the uncertainties associated with charcoal production.

TABLE 4.3.3 (NEW)
DEFAULT UNCERTAINTY ASSESSMENT FOR EMISSION FACTORS FROM CHARCOAL PRODUCTION

Technology	CH_4	N_2O
Charcoal production [a]	-90 to +900%	-90 to +900%
Biochar production [b]	–	–
Flame curtain biochar kilns	±200%	Order of magnitude

Note:

[a] Expert judgement. Having an uncertainty range from one-tenth of the mean value to ten times the mean value. The uncertainty range information is irrespective of type of kiln.

[b] Source: Cornelissen *et al.* (2016)

COKE PRODUCTION

To ensure the estimates of total fugitive GHG emissions from coke production are complete, emissions should be estimated from unintentional leakage during the coke production process and from any venting or flaring of coke oven gases.

Please refer to Section 4.2, Volume 3 for the methods to estimate process emissions from metallurgical coke production.

FUGITIVE EMISSIONS FROM UNINTENTIONAL LEAKAGE

Coke is produced by the pyrolysis of coal. This is a managed thermal treatment of the coal which limits combustion or oxidation of the coal or coke product. Coal pyrolysis at high temperature is called carbonisation. The process produces coke, volatile compounds and a range of other gases. In the coke production process, the coal is heated indirectly up to 1 000 – 1 100°C for 14 – 28 hours (JRC, 2013).

Coke is the most important reducing agent used in primary metal production. Other uses of coke include as a heating fuel and feedstock.

Globally the production of coking coal and associated coke oven gas (COG) is significant. Coke oven gas is a by-product of production of coke oven coke in coke ovens, mainly from coking coal. In 2016, coking coal production was 1 040 Mt, derived coke oven coke production was 668 Mt, and coke oven gas production was 3129 PJ (IEA, 2016).

Only certain coals, for example coking or bituminous coals, with the right properties, can be converted to coke and a coking plant may blend several types to improve coke production and extend coke battery life. Other materials which contain carbon can also be included in small quantities (e.g. petroleum coke, shredded tyres). Oil or oil residues can also be added.

Older technologies include comparatively simple coke kilns or retorts which represent a low capacity basic technology with varying levels of pollution control and energy efficiency. This type of coking technology has been largely phased out in most countries (Huo et al., 2012). Since the 1940s, the coke production process has been mechanised and the materials used in the construction of the ovens have been improved without significant design modifications. Horizontal chamber coking is the most common type of coke oven. A horizontal coke oven battery may contain up to 70 ovens as large as 14 m long and 6 m high. Because of heat transfer considerations, oven widths have remained at between 0.3 and 0.6 m. Each oven in the battery holds up to 30 tonnes of coal. Some recently constructed coke oven plants have increased dimensions further.

The technology used in coke ovens can be simplified into 2 main types (AISTech, 2010):

1. **Heat recovery, with no by-product recovery**
   By-products released from the coking process are combusted within the oven. This provides the heat required for the coke-making process. The oven is a horizontal design and operates under negative pressure which means fugitive emissions from the coke oven during operation should be negligible. Primary combustion air is introduced though ports in the oven doors which partially combusts the volatiles in the oven chamber. Secondary air is introduced to complete the combustion process in flues which run under the coal bed. Heat can still be recovered from hot exhaust gases and be used for the production of heat and electricity – in such arrangements the system is called heat recovery coke making. As most of the by-products are combusted in the oven this technique eliminates the need for costly flue gas and wastewater treatment infrastructure. Heat recovery coking has a smaller output of blast furnace coke compared to conventional coke-making systems, but, it provides more flexibility for coal selection than conventional slot ovens. Flaring of COG is very unlikely.

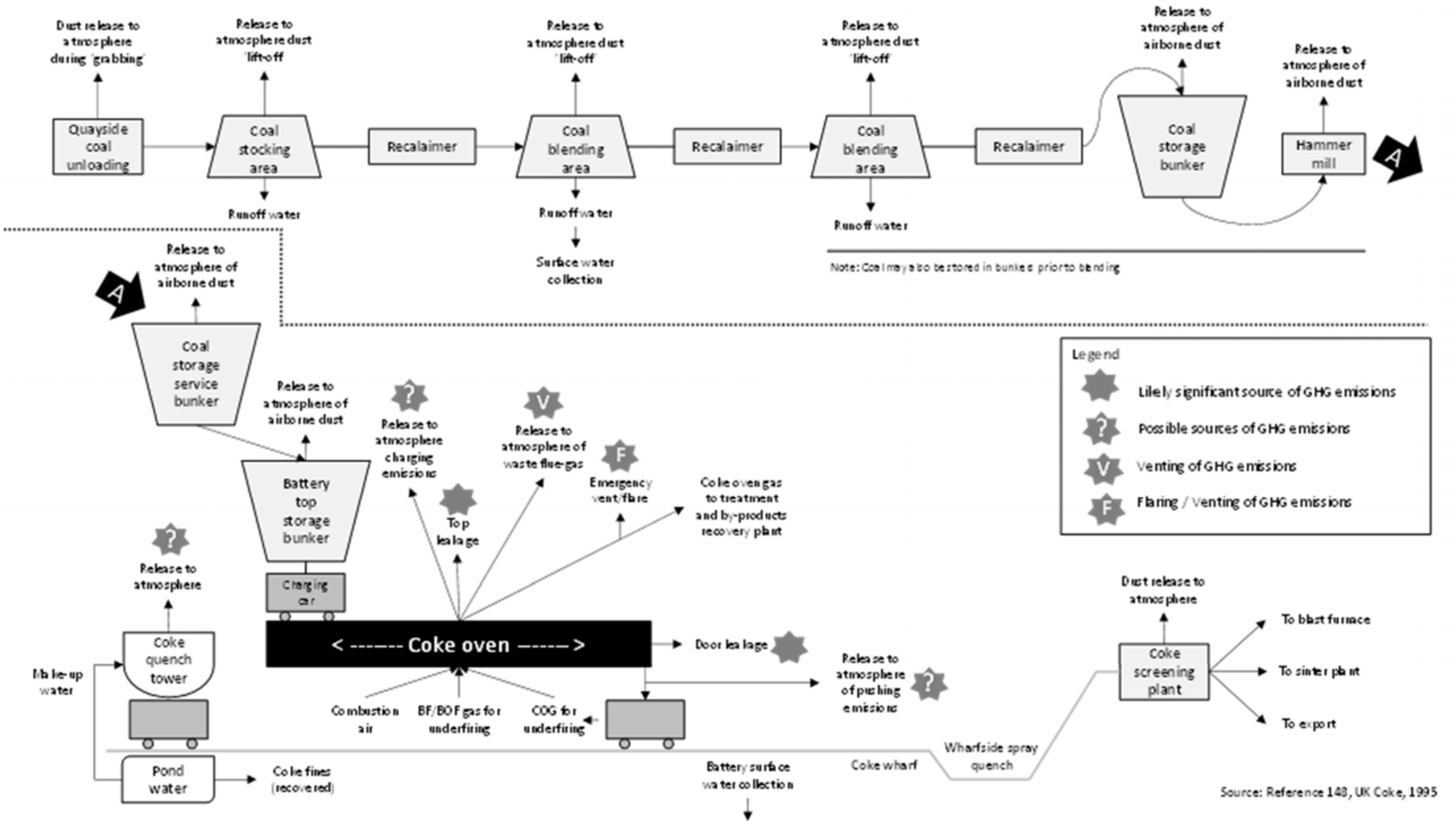
2. **Non-heat recovery, with by-product recovery**
   By product coke making is so called because the volatile matter evolved during the coking process is collected and refined into by-product chemicals. The coking process is performed in narrow, tall slot

ovens which operate under a non-oxidizing atmosphere. A positive pressure within the oven cavity prevents air ingress and subsequent combustion of the volatile matter. However this positive pressure may increase fugitive emissions, particularly if the door seals are not fully effective. Ovens typically range in height from 4 m up to 8 m in the latest plants. Taller ovens allow greater amounts of coke to be produced per oven, therefore minimizing the number of charges and pushes and related emissions to make the needed tonnage. Volatiles driven off during the coking process pass through a collector main to the by-product chemical plant. Flaring of COG is possible.

Heat recovery coke making has gained importance during recent years, although this technique is not applied in Europe to date. Only approximately 5 % of worldwide coke making facilities are operated as heat recovery plants. There are relevant plants in the US, South America, Asia and Australia. (JRC, 2013). Heat recovery coke making needs oven systems which differ in design when comparing with conventional horizontal chamber systems (JRC, 2013).

Figure 4.3.2 shows a typical flow diagram of a coke oven plant showing all sources of emissions. The processes in the diagram have been generalized, and apply to both heat recovery and non-heat recovery plants.

Figure 4.3.2 (New) Typical flow diagram of a coke oven plant showing emissions sources



The coke-making process can be subdivided into several stages. Fugitive emissions of varying intensities are possible at each of these stages:

- coal handling and preparation;
- battery operation (coal charging, heating/firing, coking, coke pushing, coke quenching);
- coke oven gas (COG) treatment with recovery and treatment of by-products in the case of a conventional coking plant; recovery of the heat of the coking and treatment of the flue gas in the case of a heat recovery coking plant.

METHODOLOGICAL ISSUES

CHOICE OF METHODS, DECISION TREES, TIERS

There are many potential sources of fugitive emissions from the coking process. Table 4.3.4 provides a summary of likely emissions according to coke production processing stage.

Inventory compilers who are using a carbon mass balance approach to estimate emissions from the iron and steel sector, and are including fugitive emissions in this balance, should not use the methods in this section to estimate emissions of CO_2 to avoid double counting.

TABLE 4.3.4 (NEW)
SOURCES OF FUGITIVE GREENHOUSE GAS EMISSIONS FROM COKE PRODUCTION ACCORDING TO PROCESSING STAGE AND REPORTING OF EMISSIONS

Coke production processing stage	Summary of activity (operation)	Likelihood of fugitive emissions (Y = Yes; P = possible; N = none of significance)			Source and significance of fugitive emissions	Notes	Reporting			
									Fugitive emissions	
		CO_2	CH_4	N_2O			Carbonisation process emissions	Combustion emissions	Non-flaring Fugitives	Flaring
coal handling and preparation, and charging	• The coke ovens are charged with prepared coal • Stamp charging might be used to compact the coking coal	N	Y	N	• CH_4 emissions might occur, especially from very gassy coal • CH_4 emissions release possible from introducing the coal into the warm oven or displacement of any COG in the empty oven	• Emissions of CH_4 from very gassy coal in storage prior to use in the coking ovens are not considered as part of this methodology • These emissions should be considered as part of coal handling and storage under 1.B.1.a.i.2	NO	NO	1.B.1.c	NO
heating and firing of the chambers	• The individual coke oven chambers are separated by heating walls • In order to improve energy efficiency, regenerators are located directly under the ovens, exchanging heat from flue-gases with combustion air and/or process gases (COG)	N	P	N	• CH_4 emissions could occur, especially from very gassy coal • Emissions might occur if the heating walls are not completely gas-tight	• If the heating walls are not completely gas-tight because of cracks, coke oven gas produced during coking will reach the flue-gas and will cause incomplete combustion resulting in emissions at the stack	NO	1.A.2.a	1.B.1.c	NO
coking	• The complete coking process takes around 14 – 28 hours, depending e.g. on the width of the oven (in case of heating by the side), the density of coal and on the quality of the desired coke (e.g. use in foundries or blast furnaces)	N	P	N	• Fugitive emissions could occur through leakage of unburnt COG because of poor sealing in the coke batteries, particularly around the door seals, and, from any flaring of the COG produced • The magnitude of the emissions could vary from insignificant to perhaps 5% (upper limit) of the COG produced[a]	• Emissions from the fuel used to heat the coke batteries should be reported in the energy sector using the methodologies set out in the stationary combustion chapter • Coke yield and COG production and composition depend, to a large extent, on coal composition and coking time	2.C.1	NO	1.B.1.c	NO
coke pushing	• Fully-carbonised coke is pushed out of the oven into a container by the ram of the pusher machine usually in less than one minute	N	P	N	• Possibility of very small emissions of CH_4 as the coke is pushed out of the batteries from residual COG in the coke batteries	• Fugitive emissions from this activity will be very small relative to the other likely fugitive emissions from coke production	NO	NO	1.B.1.c	1.B.1.c

TABLE 4.3.4 (NEW) (CONTINUED)
SOURCES OF FUGITIVE GREENHOUSE GAS EMISSIONS FROM COKE PRODUCTION ACCORDING TO PROCESSING STAGE AND REPORTING OF EMISSIONS

Coke production processing stage	Summary of activity (operation)	Likelihood of fugitive emissions (Y = Yes; P = possible; N = none of significance) CO_2	CH_4	N_2O	Source and significance of fugitive emissions	Notes	Reporting: Carbonisation process emissions	Reporting: Combustion emissions	Reporting: Fugitive emissions: Non-flaring Fugitives	Reporting: Fugitive emissions: Flaring
coke quenching	• Wet quenching and dry quenching techniques can be used • Wet quenching consumes large volumes of water. The temperature of the coke is reduced from 1 100 to 80 °C to avoid combustion • For dry quenching, the quenching car takes the hot coke to a vertical quenching chamber. Inert quenching gas circulates around the chamber, which is isolated from the atmosphere, preventing combustion whilst cooling the coke. The gas is cooled by a heat exchanger in order to recover thermal energy	N	P	N	• Possibility of very small emissions of CH_4 from residual COG as the coke is quenched with water. Some reactions of the hot coke with the quenching water are likely	• Fugitive emissions from this activity will be very small relative to the other likely fugitive emissions from coke production	NO	NO	1.B.1.c	NO
Flaring of COG	• Surplus coke oven gas may be flared if no other economic uses have been found for it, or for operational safety reasons	Y	Y	Y	• Emissions of N_2O and CH_4 from flaring are likely to be higher than those from combustion	• Flaring emissions are counted as fugitive emissions	NO	NO	1.B.1.c	NO

Notes:
[a] Routine flaring of large percentages of the COG produced is very unlikely, as it valuable as a fuel. Of the three by-product gases (BFG, COG, BOFG) produced in an integrated iron and steel works, COG has the highest caloric value.
NO Emissions Not Occurring

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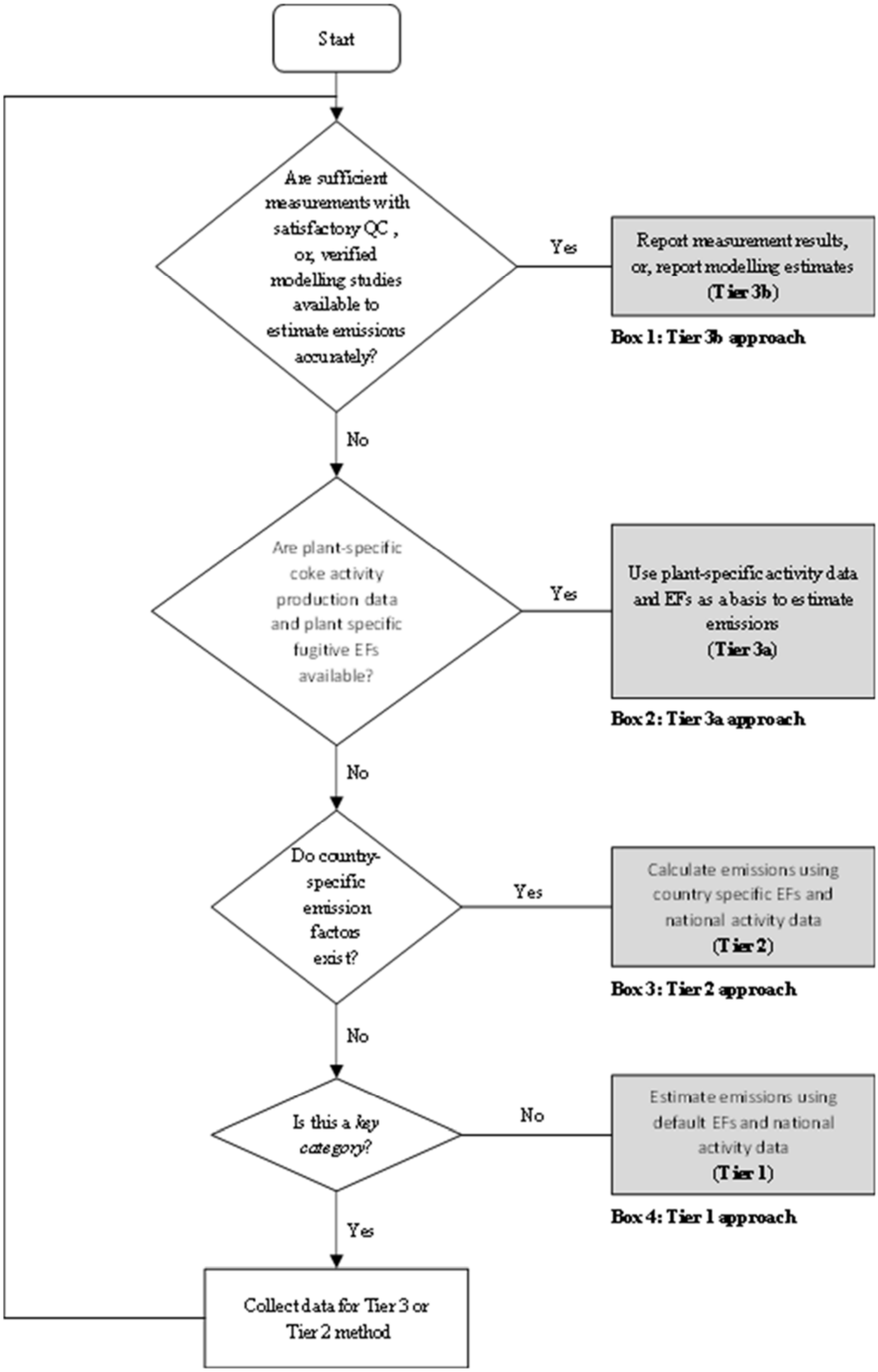
Figure 4.3.3 (New) Decision tree for estimating fugitive emissions from coke production processes



Fugitive emissions can occur during coking operations from leakages at the battery, for example, because of leakage from vessels, oven doors, flanges, or at the by-product plant. Fugitive emissions occur also from the ascension pipe and charging hole sealings. The magnitude of these emissions will depend on the coke oven technology and the level of maintenance. The variability in the magnitude of fugitive emissions will be large.

Specific door emissions vary widely depending upon the type of doors, the size of ovens and the quality of maintenance. Maintenance can be a determining factor. Examples of good results with traditional (knife-edged) doors on well-maintained small ovens and poor results with modern flexible sealing doors on poorly maintained large ovens can be found (Eurofer, 2007).

Because of the high costs of leakage monitoring, there is very little actual data available for fugitive emissions caused by battery operation.

Coking coal in storage prior to being used in coke batteries may degas and release CH_4. The guidance in this section does not cover the release of CH_4 from gassy coal. Inventory compilers should be aware of the possibility of emissions from this source and estimate and report emissions following the guidance in Section 4.1 of this chapter.

Tier 1

The general form of the equation for estimating emissions for a Tier 1 approach, based on coke production activity, is given by Equation 4.3.2 below.

EQUATION 4.3.2 (NEW)
FUGITIVE GHG EMISSION FROM COKE PRODUCTION

$$Emissions_{\ GHG} = Activity_{\ coke\ production} \bullet Emission\ Factor_{\ GHG}$$

Where:

$Emissions_{GHG}$	= emissions of a given GHG by coke production (kg GHG)
$Activity_{coke\ production}$	= amount of coke produced (tonnes)
$Emission\ Factor_{GHG}$	= default emission factor for each GHG (kg GHG/tonne of coke produced)

Tier 2

In a Tier 2 methodology, inventory compilers can use the amount of coke produced, in combination with country specific emission factors for each GHG.

Tier 3

There are a range of possible Tier 3 approaches. All methodologies used should be transparently documented.

In a Tier 3 methodology, inventory compilers can use the amount of coke produced by each plant in combination with emission factors, for each GHG, according to coke production processing stage. A Tier 3 approach for one or more plants could be combined with lower Tier approaches for other plants to derive a national estimate.

It is often the case that coverage of plant level data does not correspond exactly to coverage of classifications within the national energy statistics, and this can give rise to difficulties in combining the various sources of information. Methods for combining data are discussed in Chapter 2 of Volume 1 on General Guidance and Reporting.

Inventory compilers may also use fugitive emission measurement data for one or more of the coke processing stages, or, possibly use a model. Ensure that only fugitive emissions are measured, and that combustion emissions are not included in any measurements.

If measurements of fugitive emissions are used, it is *good practice* for inventory compilers to explain the rationale behind the emission measurement campaign, how measurements were made, and, if the measurements are applicable to individual coke batteries only, or, can be applied more widely to other batteries in the country also. Inventory compilers should present supporting information to justify that the measurement results reflect plant performance, such as information on the frequency and duration of the measurements and whether the plant was operating under normal conditions. Any measurement campaigns should focus on the sources in Table 4.3.4 associated with the greatest likelihood of emissions.

Any models used should be verified. Volume 1, Chapter 6 provides guidance on verification approaches that can be used.

CHOICE OF EMISSION FACTOR

Table 4.3.5 provides default emission factors for fugitive emissions from coke production for use with the Tier 1 methodology.

TABLE 4.3.5 (NEW)
DEFAULT EMISSION FACTORS FOR FUGITIVE EMISSIONS FROM COKE PRODUCTION

Gas	Emission Factor	Source
CH_4	0.049 kg / tonne	(Hensmann, Haardt, & Ebert, 2011)

Notes:

* Factor for “hard-coal-coke production (coking plants)” using horizontal coke batteries. Non-heat recovery ovens

* Hensmann, Haardt, & Ebert, 2011. "Emissionsfaktoren zur Eisen- und Stahlindustrie für die Emissionsberichterstattung". BFI 2011 "Emissionsfaktoren zur Eisen- und Stahlindustrie für die Emissionsberichterstattung“, im Auftrag des Umweltbundesamtes, BFI 2011, FKZ 3707 42 301.

CHOICE OF ACTIVITY DATA

The quantities of coke produced may form the input to methods used to estimate fugitive emissions. Coke production data is normally available in national energy balance data. Plant specific coke production data may also be available.

UNCERTAINTY ASSESSMENT

The quantities of coke produced are likely to be well known. Uncertainty estimates of production may be available from energy balance data, or, from plant operators. Fugitive emissions of CH_4 and N_2O will be highly uncertain, and, order of magnitude uncertainties on emissions are likely and can be assumed as a first approximation.

Table 4.3.6 provides the uncertainties associated with coke production.

TABLE 4.3.6 (NEW)
DEFAULT UNCERTAINTY ASSESSMENT FOR EMISSION FACTORS FROM COKE PRODUCTION

Oven technology	CH_4	N_2O
Overall assessment for all technologies	-90% to +900%[a]	-90% to +900%[a]

Note:

[a] Having an uncertainty range from one-tenth of the mean value to ten times the mean value.

Source: Expert judgement

FLARING OF COKE OVEN GAS EMISSIONS

Surplus coke oven gas may be flared if no other economic uses have been found for it, or for operational safety reasons and equipment maintenance purposes. Box 4.1 provides a summary of flaring activities in metallurgical coke and iron and steel production.

BOX 4.3.1 (NEW)

FLARING ACTIVITIES IN METALLURGICAL COKE AND IRON AND STEEL PRODUCTION

Gaseous products from metallurgical coke and iron and steel production are mainly used for the production of heat and electricity, and in some cases, as reducing agents. A minor proportion of the total gas produced, usually less than 5%, which is lost from the production stream and then flared. This flaring occurs mainly during emergencies or during maintenance activities.

Integrated iron and steel facilities usually flare a mix of the gases produced, including coke oven gas (COG), blast furnace gas (BFG) and converter gas (LDG), at the same stacks. This situation represents a challenge for the GHGs emissions reporting, because:

- GHGs emissions from COG flaring should be reported in the energy sector, category 1.B
- GHGs emissions from BFG and LDG flaring should be reported under IPPU.

IN AN INTEGRATED STEELWORKS IF THERE ARE FLARES OF COMBINED GASES WHERE THE ESTIMATES FOR COG, BFG AND LDG CANNOT BE DETERMINED, THEN IT IS CONSIDERED *GOOD PRACTICE* TO REPORT THE EMISSIONS IN IPPU AND SEEK TO MINIMISE THE RISK OF DOUBLE-COUNTING OF EMISSIONS REPORTED ELSEWHERE IN THE INVENTORY. TO MINIMISE THIS RISK, IT IS IMPORTANT TO CONSIDER THE METHODS USED FOR ESTIMATING EMISSIONS FROM COKE OVENS AND THE OTHER EMISSION SOURCES IN THE INTEGRATED WORKS.

In typical operation of an integrated steelworks, flaring and other losses of COG are minimised due to its high energy content. BFG is also generally used but in some cases the percentage flared rate is upto 20%. Typically, LDG is totally or partially flared; however, in some cases it is directly discharged into the atmosphere. Typical ranges for gas flared rates are:

GAS FLARED (%)	
COKE OVEN GAS (COG)	**0.3 TO 2**
BLAST FURNACE GAS (BFG)	**0.5 TO 20**
CONVERTER GAS (LDG)	**5.0 TO 100**

METHODOLOGICAL ISSUES

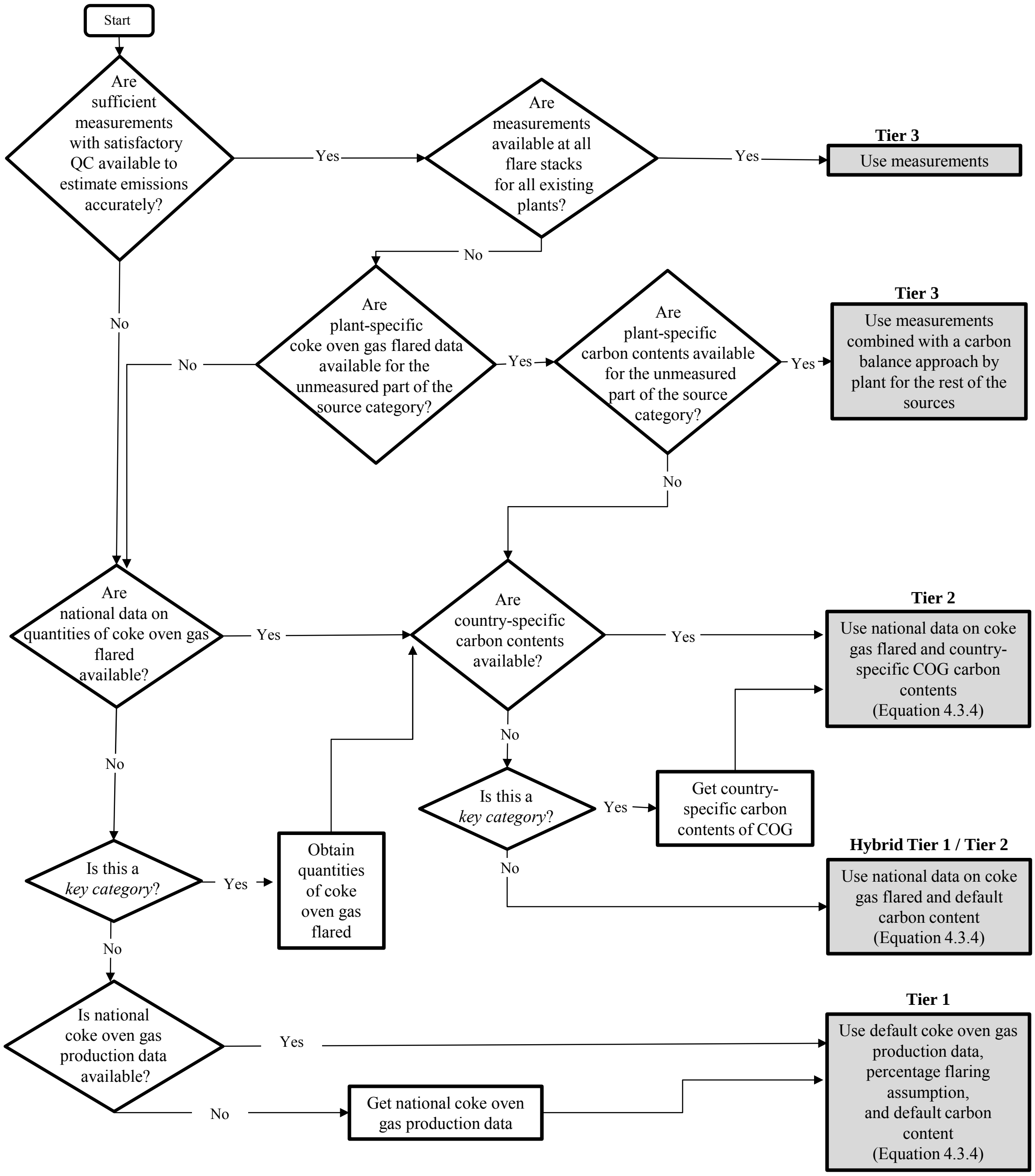
CHOICE OF METHODS, DECISION TREES, TIERS

For coke oven gas flaring, there are three tiers than can be used to calculate CO_2 emissions and two tiers to calculate CH_4 and N_2O emissions.

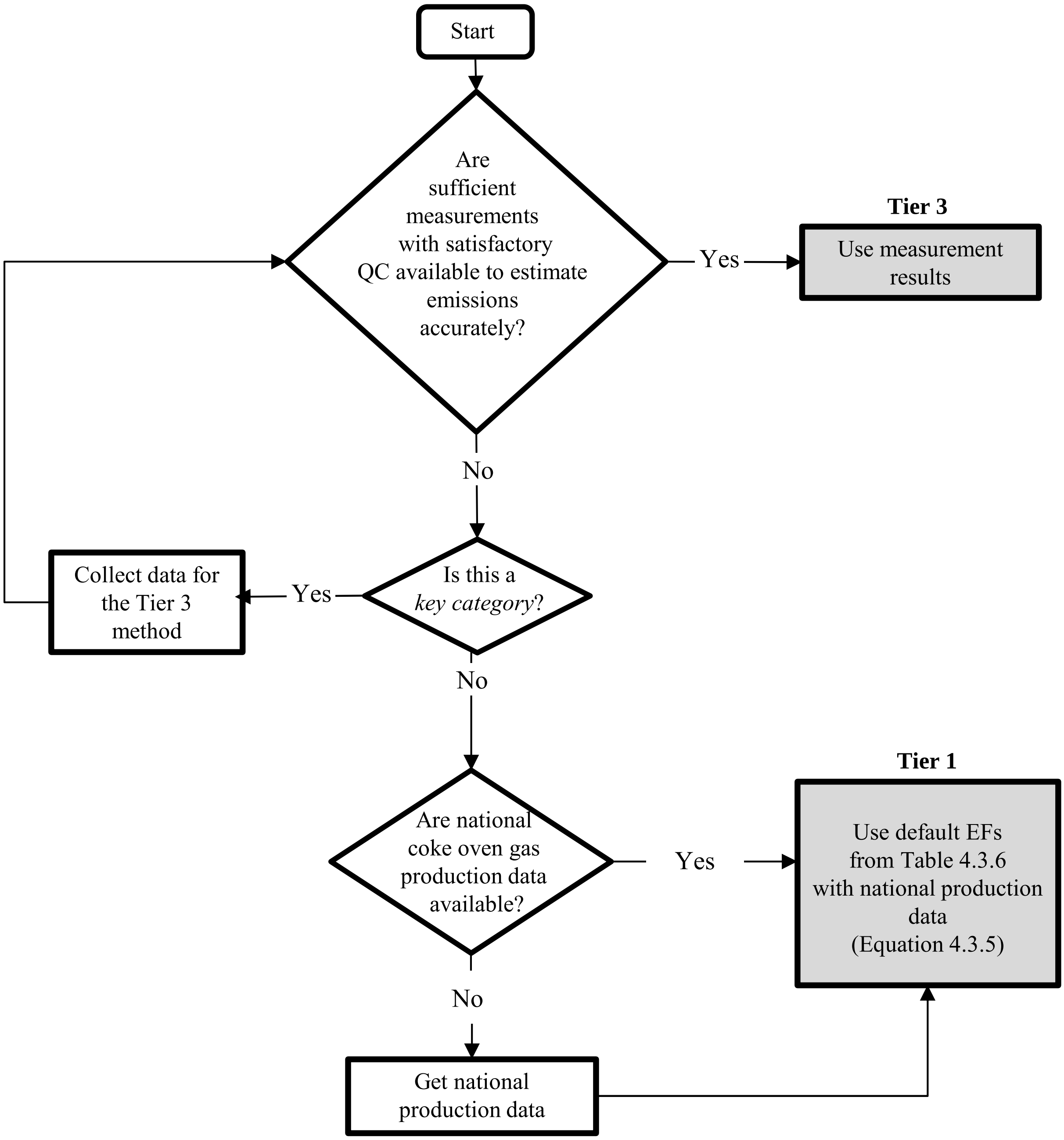
The decision tree in Figure 4.3.4 will help select the Tier to use to estimate CO_2 emissions. To select the Tier for CH_4 and N_2O, use the decision tree in Figure 4.3.5.

When estimating the emissions of CO_2 from flaring of coke oven gas, it is important to ensure there is no double counting of emissions that might have been made as part of carbon balance calculations made in the iron and steel sector.

Figure 4.3.4 (New) Decision tree for estimating CO_2 emissions from coke oven gas flaring



2832 **Figure 4.3.5 (New) Decision tree for estimating fugitive emissions of CH_4 and N_2O from coke**
2833 **production process**



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Tier 1 / Tier 2– CO_2

The general form of the equation for estimating emissions for a Tier 1 approach, based on coke production activity, is given by Equation 4.3.3 below.

EQUATION 4.3.3 (NEW)
FUGITIVE CO_2 EMISSIONS FROM THE FLARING OF COKE OVEN GAS

$$Emissions_{CO2} = (Activity_{coke\ oven\ gas\ flared} \bullet CC_{coke\ oven\ gas}) \bullet 44/12$$

Where:

Emissions $_{CO2}$ = emissions of CO_2 by coke oven gas flared (kg CO_2)

Activity $_{coke\ oven\ gas\ flared}$ = amount of coke oven gas flared (GJ)

CC $_{coke\ oven\ gas}$ = Carbon content of coke oven gas (kg of carbon per GJ of coke oven gas)

The Tier 1 approach for CO_2 assumes that 2% (by volume) of the coke oven gas produced is removed from the production stream and then flared (see Box 4.1). A default carbon content for coke oven gas should be used, taken from Table 1.3, Volume 2, Chapter 1, *2006 IPCC Guidelines*.

The Tier 2 approach for CO_2 requires knowledge of the amount of coke oven gas flared in the country, and the use of country specific carbon content of the coke oven gas produced. If country specific carbon contents for coke oven gas are not available, default carbon contents could be used. In this case the methodology is a hybrid between Tier 1 and Tier 2, and is not appropriate to use this if flaring of coke oven gas is a *key category*.

Tier 3– CO_2

The Tier 3 method requires the collection, compilation and aggregation of facility-specific measured emissions data. It is *good practice* for inventory compilers to explain the rationale behind the emission measurement campaign and how measurements were made. If monitoring data are not available, the Tier 3 method can be estimated by applying equation 4.3.4, based on facility-specific data of coke oven gas flared and coke oven gas carbon content. The total national emissions will equal the sum of emissions estimated for each facility.

Tier 1– CH_4 and N_2O

Tier 1 approach for CH_4 and N_2O from coke oven gas flaring is given by Equation 4.3.4 below.

EQUATION 4.3.4 (NEW)
FUGITIVE CH_4 AND N_2O EMISSION FROM THE FLARING OF COKE OVEN GAS

$$Emissions_{CH4,\ N2O} = Activity_{coke\ oven\ gas\ produced} \bullet Emission\ Factor_{CH4,\ N2O}$$

Where:

Emissions $_{CH4,\ N2O}$ = emissions of CH_4 and N_2O from coke oven gas flaring (Gg GHG)

Activity $_{coke\ oven\ gas\ produced}$ = volume of coke oven gas produced (m^3)

Emission Factor $_{CH4,\ N2O}$ = emission factor for CH_4 and N_2O (Gg of greenhouse gas per m^3 of coke oven gas produced), taken from Table 4.3.7

Tier 3–CH_4 and N_2O

The Tier 3 method requires collection, compilation and aggregation of facility-specific measured emissions data. It is *good practice* for inventory compilers to explain the rationale behind the emission measurement campaign and how measurements were made. The total national emissions will equal the sum of emissions estimated for each facility.

CHOICE OF EMISSION FACTOR

The default carbon content of COG, and, emission factors of CH_4 and N_2O from coke oven gas flaring are provided in Table 4.3.7 below.

CH_4 emission factor has been estimated according with the expression indicated in Table 4.3.7, assuming that 2% (by volume) of the coke oven gas produced is removed from the production stream and then flared, considering an average coke oven gas composition, and a default efficiency in flaring.

In flaring waste gases containing nitrogen compounds, N_2O is formed either by the fixation of atmospheric nitrogen or by the oxidation of nitrogen compounds in the fuel. Considering that the proportion of nitrogen in coke oven gas is highly variable, but the range is similar to those of the gases flared in oil and gas operation facilities, for Tier 1 approach it is assumed that the rate between CO_2 and N_2O emissions from flaring of coke oven gas is the same that those reported in Volume 2, Chapter 4 *2006 IPCC Guidelines*, Table 4.2.5, default weighted total (EPA, CFR Title 40, Chapter I, Subchapter C, Part 98.33). With this assumption, N_2O emission factor has been estimated according with the expression indicated in Table 4.3.7.

TABLE 4.3.7 (NEW)
DEFAULT FACTORS FOR FUGITIVE EMISSIONS FROM FLARING OF COKE OVEN GAS

Gas	Factor (kg C/GJ COG)	Source
CO_2	12.1	Volume 2, Chapter 4 *2006 IPCC Guidelines*. Table 1.3. Default carbon content of COG
Gas	**Emission Factor** (kg/ GJ COG production)	**Source**
CH_4	4.2 E-03	$EF_{CH_4} = R_{COG\ flared} \bullet Fvol_{CH_4 in\ COG} \bullet \bullet (1 - \eta_{flaring}) \bullet K$ Where: $R_{COG\ flared}$: is the rate of coke oven gas produced that is flared, set as 0.02. $Fvol_{CH_4 in\ COG}$: is the volumen fraction of CH_4 in COG, set as 0.28 (JRC, 2010; Man et al 2016; Nishifuji et al 2011). $\eta_{flaring}$: flare efficiency, set as 0.98 (EPA, CFR Title 40, Chapter I, Subchapter C, Part 98, Subpart W). K: A constant equal to 37.65, to convert m^3 CH_4/m^3COG to kg CH_4/Gj COG.
N_2O	9.76 E-06	$\left(EF_{N_2O}\right)_{COG\ flaring} = \left(EF_{CO_2}\right)_{COG\ flaring} \bullet \left[\left(\frac{EF_{CO_2}}{EF_{N_2O}}\right)_{Oil\ and\ gas\ production}\right]$ Where: $\left(EF_{CO_2}\right)_{COG\ flaring} = 12.1\ kg\ C/GJ\ COG \bullet \frac{44}{12} \bullet 0.02 = 0.89\ kg\ CO_2/GJ\ COG$ EF_{CO_2} and EF_{N_2O} are set as 3.0 E-03 and 3.3 E-08 Gg gas per 10^6 m^3 gas produced.

CHOICE OF ACTIVITY DATA

The amount and types of COG produced could be obtained from one, or a combination, of the sources in the list below:

- national energy statistics agencies (national energy statistics agencies may collect data on the amount and types of COG produced from individual enterprises that produce fuels);

- reports provided by enterprises to national energy statistics agencies (these reports are most likely to be produced by the operators or owners of large plants);
- reports provided by enterprises to regulatory agencies (for example, reports produced to demonstrate how enterprises are complying with emission control regulations);
- periodic surveys, by statistical agencies of the types and quantities of COG produced by a sample of enterprises.

UNCERTAINTY ASSESSMENT

If direct measurements of COG flared are used, inventory compilers should estimate and report uncertainties associated with the measurements.

Table 4.3.8 provides the uncertainties associated with the COG carbon contents and the emission factors of CH_4 and N_2O.

TABLE 4.3.8 (NEW)
DEFAULT UNCERTAINTY ASSESSMENT FOR EMISSION FACTORS FROM COKE OVEN GAS FLARING

CO_2	CH_4	N_2O
±75%	±75%	±75%

Note:
Uncertainties reproduced from Volume 2, Chapter 4 *2006 IPCC Guidelines*. Table 4.2.5. Default weighted total

Table 1.3 of Volume 2, Chapter 4 *2006 IPCC Guidelines* provides lower (10.3 kg/GJ)) and upper (15.0 kg/GJ) default carbon contents of COG. This equates to a 95% uncertainty range, in percentage terms with respect to the default factor, of -12 to +19 (see Box 3.0b, Chapter 3, Volume 1 of the *2019 Refinement*).

COMPLETENESS

When estimating the emissions of CO_2 from flaring of coke oven gas, it is important to ensure there is no double counting of the emissions accounted for non-fugitive emissions from coke production, whose methodology is described in Chapter 4, Volume 3 of the *2006 IPCC Guidelines* and in Chapter 4 Volume 3 of the *2019 Refinement*.

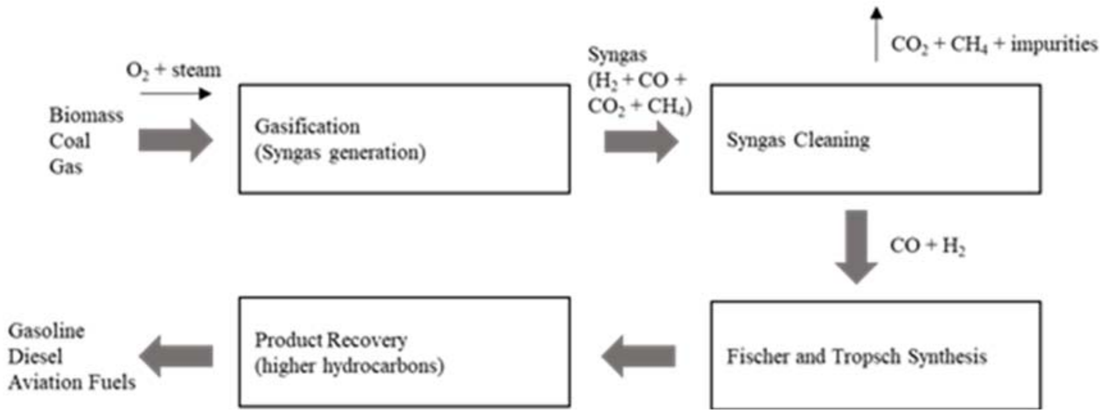
If non-fugitive emissions are estimated using Tier1b approach, it is assumed that all the coke oven gas produced is burned on site for energy recovery, and therefore CO_2 emissions from flaring are equal to zero. If Tier 2 or Tier 3 are applied to estimate emissions from non-fugitive sources, double counting are avoided if the emissions from flaring are deducted in the carbon balance (see Equation 4.2, Chapter 4, Volume 3 of the *2019 Refinement*).

4.3.2.2 GASIFICATION TRANSFORMATION PROCESSES

Gasification transformation processes are related to the transformation of biomass, coal or natural gas into syngas, composed by H_2, CO, CO_2 and CH_4, and, then, into a liquid hydrocarbons fuels. These processes are called biomass to gaseous (BtG), biomass to liquid (BtL), coal to liquid (CtL) and gas to liquid (GtL).

The syngas can be used as a fuel to generate electricity through a gas turbine or as a chemical feedstock (Van der Drift and Boerrigter, 2006; OCDE/IEA, 2007). The liquid fuels production is obtained at the Fischer-Tropsch process, where the syngas, after cleaned to remove CO_2, CH_4, impurities such as sulphur bearing compounds (in particular H_2S), and heavy metal bearing compounds, is transformed into high-quality fuels like gasoline, diesel and aviation fuels. Figure 4.3.6 shows the process of gasification transformation.

Figure 4.3.6 (New) Gasification transformation process of biomass, coal and gas



BtG and BtL are still emerging technologies, and there are currently very few large-scale plants worldwide. However, considering that they are likely to become more widely adopted, methodologies to estimate the fugitive emissions of these processes are provided in Appendix 4a.3 as indicative methodologies. It is important to highlight, however, that current data are inconsistent and improved methods and data may be available in the future. CtL and GtL fugitive emissions estimation methodologies are provided below. Table 4.3.9 shows GHGs emissions from CtL and GtL processes.

TABLE 4.3.9 (NEW)
SUMMARY OF GHG EMISSIONS FROM GASIFICATION TRANSFORMATION PROCESSES

Synthetic fuel production Process	GHGs
CtL	CO_2, CH_4, N_2O
GtL	CO_2

COAL TO LIQUIDS

Synthesis gas from CtL is generated by feeding coal into a gasification process. This synthesis gas containing a mixture of CO, H_2, CO_2 and CH_4 is fed into a gas cleaning process where impurities such as sulphur bearing compounds (in particular H_2S), and heavy metal bearing compounds are removed from the synthesis gas. After cleaning, the synthesis gas composition is adjusted in a process called water-gas shift conversion. Here the ratio of H_2 to CO_2 is adjusted to produce a synthesis gas which is optimal for Fischer-Tropsch synthesis. After water-gas shift conversion the modified synthesis gas is fed to the Fischer-Tropsch synthesis process where it reacts to produce liquid hydrocarbons. A significant fraction of CtL plant CO_2 is generated in the gasification process which needs to be separated before the syngas is fed into the FT reactor (Mantripragada and Rubin, 2011). Current production levels mainly from CtL plants are estimated at over 300,000 Barrels Per Day (BPD)[11] with a conservative annual estimate of 120 million tons of CO_2 equivalent.

GAS TO LIQUIDS

Natural gas is combined with steam and pure oxygen from a cryogenic air separation unit before it is heated and fed into an autothermal reformer (ATR). Syngas, a mixture of H_2 and CO, leaves the ATR and enters the Fischer-Tropsch (FT) synthesis reactor, where it is converted to a hydrocarbon wax. The wax exiting the FT reactor is upgraded in the product work-up unit to yield approximately 70% diesel and 30% naphtha liquid products. A steam-methane reforming hydrogen plant is required to provide hydrogen for the product upgrading as well as inlet natural gas pre-treatment. The GtL plant CO_2 is generated from several sources (Heimel & Lowe, 2009):

- Entering with the inlet natural gas (feed gas assumed to contain 1.6 mol% CO_2)
- Forming during syngas generation
- Forming in the FT reactor
- Forming in the hydrogen plant

[11] Worldwide Syngas Database by the Global Syngas Technologies Council

- Forming in the process heating furnaces

GtL technology in particular as alternative to petroleum based diesel is considered to be one of the less carbon-intensive technical options to reduce petroleum consumption in the on-road transportation sector (Hao et al, 2010). The worldwide syngas database produced by the Gasification and Syngas Technologies Council (GSTC) shows that there are more than thirty (30) projects that are either in operation or under development (GSTC, 2014). Hao et al estimated GtL capacity to be 35,000 BPD in the year 2010 and projected an increase in capacity to 1-2 million BPD by 2015 (Hao et al, 2007).

METHODOLOGICAL ISSUES

The choice of method will depend on the technologies that are operational in countries, including whether the technologies analysed in this section are *key categories* in the country, and to what extent country and plant-specific information is available or can be gathered.

The most accurate estimates for fugitive emissions, can be developed by determining the emissions on a plant-by-plant basis and/or differentiated for each feedstock category (e.g., type of biomass, coal or gas). The methods for estimating CO_2, CH_4 and N_2O fugitive emissions from these technologies vary because of the different factors that influence emission levels. N_2O emissions from coal gasification are negligible and depends on the nitrogen content of the coal.

The general approach to calculate greenhouse gas emissions from those technologies is to obtain the amount of feedstock used and to investigate the related greenhouse gas emission factors, preferably from country-specific information on the carbon content. In the case of CtL, the resultant syngas produced from gasification of coal is used as activity data.

CHOICE OF METHODS, DECISION TREES, TIERS

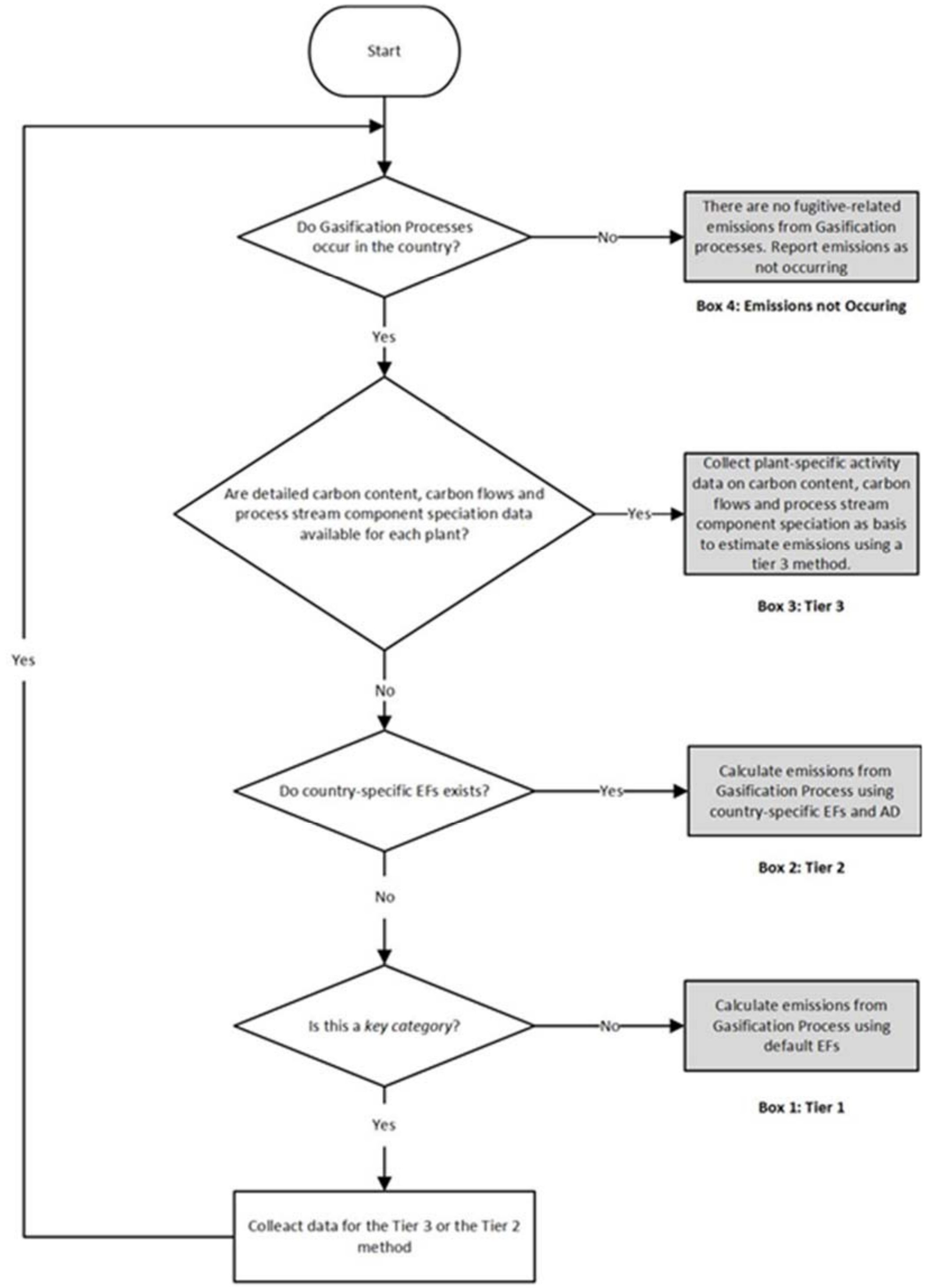
There is limited information about gasification transformation technologies and, therefore, it was considered that fugitive emissions occur only at the gasification stage. The fugitive emissions resulting from the syngas transformation at the Fischer-Tropsch (FT) stage was considered negligible, as most emissions at FT stage are related to combustion processes to produce heat.

The method for estimating fugitive emissions from GtL technologies is based on an estimate of the carbon content in the feedstock combusted and converting the product to greenhouse gases emissions. The activity data are the feedstock inputs into the gasification stage, and the emission factors are based on the carbon content of the feedstock.

The CtL process produces the bulk volume of greenhouse gas emissions during the production and treatment of syngas. This, the method for estimating fugitive emissions from CtL technologies is based on the amounts of syngas produced in terajoules.

The choice of method depends on the country specific information available, and is given in the decision tree in Figure 4.3.7.

Figure 4.3.7 (New) Decision tree for estimating emissions of CO_2, CH_4 and N_2O from Gasification Transformation processes



TIER 1

The Tier 1 method is a simple method that can be used when fugitive emissions from CtL and GtL technologies are not significant.

Fugitive emissions of CO_2, CH_4 and N_2O can be estimated from the amount of syngas (CtL) or natural gas (GtL) and the emission factor of fugitive emission. The application of a Tier1 approach is done using Equation 4.3.5 presented below.

EQUATION 4.3.5 (NEW)
FUGITIVE GHG EMISSIONS FROM GASIFICATION PROCESSES

$$E_{gas\ i} = (FSj \bullet EFi) \bullet 10^{-6}$$

Where:

$E_{gas\ i}$ = direct amount (Gg/yr) of GHG gas *i* emitted at gasification station of CtL and GtL facilities (CO_2, CH_4 and N_2O)

FS_j = total amount of feedstock of type *j* (TJ) in the case of GtL and total amount of syngas produced (TJ) in the case of CtL

EF_i = gas *i* emission factor, kg gas *i*/TJ of feedstock *j* (GtL) or gas *i* emission factor, kg gas *i*/TJ of syngas produced (CtL)

10^{-6} = conversion factor from kilogram to Gg

TIER 2

CtL and GtL plants are versatile and depending on their process unit arrangement downstream, they are able to produce a wide range of products. Some CtL/GtL plants are able to produce a combination of liquid fuels and chemicals (e.g. Ammonia (NH_3), Nitric Acid (HNO_3), methanol (CH_3OH), etc.). This in turn affects the rate at which syngas is produced upstream. The quality of coal used determines the quality of syngas and the effort needed to treat syngas. Hence, it is *good practice* to develop a Tier 2 emission factor based on plant-specific emission factors as opposed to country-specific emission factors that are developed by aggregating plant-level emission factors for a country in question.

TIER 3

The most appropriate Tier 3 approach is a material balance methodology. This is largely because, the CtL process in particular is a very versatile process. Depending on the type and volume of downstream products (chemicals or liquid fuels), the amount of syngas to be processed via the Fischer-Tropsch process can be varied. That in turn, affects the amount of syngas that needs to be produced upstream. Variation in the production of syngas affects the amount of Greenhouse Gas emissions released in the atmosphere. Secondly, the syngas production and treatment processes release a large volume of flue gas stream that is almost impossible to measure. Hence, a direct measurement methodology is not ideal for CtL and GtL processes. Preferable a Tier 3 stoichiometric/mass-balance methodology should be followed.

CHOICE OF EMISSION FACTOR

Coal to liquids

Higman and van der Burgt (2008) presents process-specific CO_2, CH_4 and N_2O emission factors as a function of syngas production and by process type. It is worth noting that for the CtL process, the bulk volume of greenhouse gas emissions are released during the production and treatment of syngas. Table 4.3.8 presents emission factors reported by Higman and van der Burgt. These emission factors have been developed for typical current international values and ranges of coal qualities (20.7 -27.3 kJ/kg HHV). Coal Gasification systems considered are the Air Separation Unit (ASU), Oxygen blown fixed-bed BGL 1000 gasifier, acid gas removal (Rectisol).

TABLE 4.3.10 (NEW)
EMISSION FACTORS FOR GASIFICATION PROCESSES OF CTL

System Output	Syngas	Syngas/H_2	SNG[a]
[b]CO_2 emissions, kg CO_2/TJ total output	55 000	55	78
[b]CH_4 emissions, kg CH_4/TJ total output	6.1	0.0061	0.0061
[b]N_2O emissions, kg N_2O/TJ total output	0	0	0

[a] Synthetic Natural Gas.

[b] Higman, van der Burgt: "Gasification", 2nd edition (2008).

Gas to liquids

Jaramillo et al. analysed CO_2 emissions released during syngas production in CtL and GtL plants (Jaramillo et al, 2008). The study by Jaramillo et al (2008) assumes that slightly more diesel is produced than gasoline. This assumption is plausible given that a conventional GtL plant produces 62% Diesel, 44% gasoline and 3% propane (Jaramillo et al, 2008). The CO_2 emission factor is therefore derived from the inputs and outputs of a conventional GtL plant by dividing the amount of carbon lost (assuming 100% oxidation) with the volume of natural gas input to produce syngas. CO_2 is the most dominant GHG in the GtL process and therefore, it is a conservative approach to assume that 100% of carbon lost to the atmosphere is CO_2. Table 4.3.11 presents CO_2 emission factors of GtL gasification process.

TABLE 4.3.11 (NEW)
EMISSION FACTOR FOR GASIFICATION PROCESSES OF GTL

Process	EF CO_2 (kgCO_2/TJ natural gas input)
Gas to liquids	6 026[a]

[a] Own construction based on converting from mass units for natural gas to energy units

CHOICE OF ACTIVITY DATA

Coal to liquids

The activity data required for a Tiers 1 and 2 are the amounts of syngas produced in terajoules (TJ). Since this data is monitored continuously at individual plant level, it is *good practice* to collect syngas production data from each plant.

For the Tier 3 method, carbon mass flow and species composition data is required to accurately quantify the amount of GHGs in the flue gas streams. Even though the amount of syngas produced is not necessary as activity data for a Tier 3 method, it is *good practice* to collect and report these data in comparing the results of the Tier 3 method (material balance) against the Tier 1 method.

Gas to liquids

The activity data required for Tiers 1 and 2 is the amounts of natural gas inputs into the GtL process in terajoules (TJ). Natural gas may be used upstream of the GtL plant for heat and electricity production during production. Therefore, it is *good practice* to ensure that the amount of natural gas used for electricity and heat during natural gas production is separated from the amount of natural gas used as a feedstock in the GtL plant. Inventory compilers have to use default density at standard temperature and pressure for natural gas to convert the amount of natural gas inputs from volumetric basis to mass basis.

For a Tier 3 method, carbon flows and species composition are required to quantify the amount of carbon in each process stream and process unit inside a GtL plant. This information is monitored continuously during process control and therefore should be readily available from each plant.

UNCERTAINTY ASSESSMENT

Gasification Transformation Processes

Estimates of fugitive emissions from gasification transformation processes can be highly uncertain due to lack of information about these technologies. More research and development is needed on these technologies, especially direct measurement on all stages to confirm which ones present fugitive emissions.

Activity data uncertainties

The quantities of of feedstocks used (e.g. in the cased of GtL or biomass) or syngas produced (e.g. in the case of CtL) are likely to be well known. Uncertainty estimates of production may be available from energy balance data, or, from plant operators. Fugitive emissions of CO_2, CH_4 and N_2O will be highly uncertain, and, order of magnitude uncertainties on emissions are likely and can be assumed as a first approximation.

Emission factor uncertainties

Considering the minimal literature and the absence of large scale fuel transformation processes, fugitive emission factors provided in these guidelines were estimated based on a very few data, resulting in a high level of uncertainty. Table 4.3.12 provides the uncertainties associated with the emission factors of CO_2, CH_4 and N_2O

TABLE 4.3.12 (NEW)
DEFAULT UNCERTAINTY ASSESSMENT FOR EMISSION FACTORS FROM GASIFICATION TRANSFORMATION PROCESSES

Gasification transformation process technology	CO_2	CH_4	N_2O
Overall assessment for all technologies	-90% to +900% [a]	-90% to +900% [a]	-90% to +900% [a]

Note:

[a] Having an uncertainty range from one-tenth of the mean value to ten times the mean value.

Source: Expert judgement

4.3.3 Completeness

This section of the GLs is currently not able to provide a set of methods to estimate fugitive emissions from all the possible parts of each of the sources. But it is *good practice* for inventory compliers to ensure completeness and to try and estimate emissions if possible. But resources should be prioritised according to the *key category* analysis results.

Where a country has estimated its fugitive emissions based on an aggregation of estimates reported by individual plants, it is *good practice* to document the steps taken to ensure that these results are complete, transparent and consistent across the time series. Corrections made to account for companies or facilities that did not report, and measures taken to avoid missed or double counting (particularly where ownership changes have occurred) and to assess uncertainties should be highlighted.

4.3.4 Developing consistent time series

Ideally, emission estimates will be prepared for the base year and subsequent years using the same method. The aim is to have emission estimates across the time series reflect true trends in greenhouse gas emissions. Emission or control factors that change over time (e.g., due to changes in source demographics or the penetration of control technologies) should be regularly updated and, each time, only applied to the period for which they are valid. For, example, if an emission control device is retrofit to a source then a new emission factor will apply to that source from then onwards; however, the previously applied emission factor reflecting conditions before the retrofit should still be applied for all previous years in the time series. If an emission factor has been refined through further testing and now reflects a better understanding of the source or source category, then all previous estimates should be updated to reflect the use of the improved factor and be reported in a transparent manner.

A country should assess which technologies and practices are generally in place in the country and apply the corresponding emission factor. As technologies and practices change over time, it is possible that a country will use one EF in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series.

Where some historical data are missing, it might still be possible to use source-specific measurement results combined with back-casting techniques to establish an acceptable relationship between emissions and activity data in the base year. Approaches for doing this will depend on the specific situation, and are discussed in general terms in Volume 1 Chapter 5 of the *2006 Guidelines*.

If emission estimates are developed based on an aggregation of individual company estimates, greater effort will be required to maintain time series consistency, particularly where frequent facility ownership changes occur and different methodologies and emission factors are applied by each new owner without also carrying these changes back through the time series.

4.3.5 Inventory Quality Assurance/Quality Control (QA/QC)

Specific QA/QC procedures to optimise the quality of estimates of emissions are given in Chapter 6 of Volume 1, General Guidance and Reporting.

The bullet point list below identifies *good practice* in estimating fugitive emissions from the sources included in this section of the guidance:

- **charcoal and biochar production**: it is *good practice* **charcoal and biochar production**: it is *good practice* to ensure that emissions from charcoal and biochar production are based on proper measurements of charcoal and biochar produced since measurements of traditionally produced charcoal is based number of bags produced.
- **coke production**: it is *good practice* to try and confirm that emissions are realistic in magnitude in comparison with emissions from other categories in the iron steel sector. Fugitive emissions should be a very small fraction of the total emissions in the iron steel sector.
- For fugitive emissions from CtL and GtL, it is *good practice* to ensure that the quantity of feedstocks used (e.g. natural gas for GtL and coal used to produce syngas in the case of CtL) is comparable to the amount of natural gas and coal reported as feedstock which is subtracted in the reference approach for CO_2 under stationary combustion.
- **biomass to liquids:** it is *good practice* to confirm which stages present fugitive emissions.
- **biomass to gas:** it is *good practice* to confirm which stages present fugitive emissions.

4.3.6 Reporting and Documentation

It is *good practice* to document and archive all information required to produce the national emissions inventory estimates, as outlined in Volume 1 Chapter 8 of the *2006 Guidelines*.

It may not be practical to include all supporting documentation in the inventory report. However, at a minimum, the inventory report should include summaries of the methods used and references to source data such that the reported emissions estimates are transparent and the steps in their calculation may be retraced. For segments where a technology- or practice-specific Tier 1 emission factor is used, the rationale for selecting that factor and the method for applying the factors over the time series must be clearly documented. It is expected that many countries will use a combination of methodological tiers to evaluate the amount of fugitive greenhouse gas emissions. The specific choices should reflect the relative importance of the different subcategories and the availability of the data and resources needed to support the corresponding calculations.

Recalculations should be clearly documented, explaining changes that have been made to emission factors, or methodologies. The steps taken to ensure time series consistency should be documented.

The above reporting and documentation guidance is applicable to all methodological choices. Where Tier 3 approaches are employed, it is important to ensure that either the applied procedures are detailed in the inventory report or that available references for these procedures are cited since the IPCC Guidelines do not describe a standard Tier 3 approach.

Annex 4A.1 Standard Conditions

Standard conditions

The Tier 1 EFs listed in the Tables 4.2.4 – 4.2.4k are sensitive to temperature and pressure. Activity data must be consistent with the EFs standard conditions. The EFs are given at the most commonly used standard conditions: 15°C and 101.325 kPa (1 atm). If activity data are derived at reference conditions, which are different from those used by the Tier 1 EFs, the inventory compiler should harmonize activity data with 15°C and 101.325 kPa. Pressure is normally fixed for most of the standard conditions at the level of 101.325 kPa (1 atm). Thus, in general, probable variations of reference temperature should be considered as a priority.

Along with the physical state, activity data can be split into liquids (oil) and gases (natural gas and associated petroleum gas). Different correction approaches of gases and liquids are required.

Liquids (oil)

Liquids may be referenced at 20°C and 15°C. In order to harmonize oil units referenced at 20°C to the Tier 1 EFs, correction can be made with the use of international standard tables of conversion factors (CFs) and densities based on detailed data on oil properties. Standard tables can be found in internationally recognized sources as follows:

- ASTM D 1250-8 Standard Guide for Use of the Petroleum Measurement Tables issued by American Society for Testing and Material (ASTM International 2013)
- API MPMS 11.1:2004. American Petroleum Institute. Manual of Petroleum Measurement Standards Chapter 11 - Physical Properties Data Section 1 - Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils (American Petroleum Institute (API) 2004)

As follows from the standard, the correction approach is based on the equations listed below (Equations 4A.1.1 to 4A.1.3) ((GOST 2012) R 8.595-2010):

EQUATION 4A.1.1 (NEW)
CONVERSION OF OIL DENSITY AT 15°C

$$\rho_{15} = \rho_{20} \cdot K_{15}$$

EQUATION 4A.1.2 (NEW)
CONVERSION OF RELATIVE OIL DENSITY AT 15.556°C (60°F)

$$\rho_{60/60} = \rho_{20} \cdot K_{60/60}$$

EQUATION 4A.1.3 (NEW)
CONVERSION OF API DENSITY

$$\rho_{API} = \rho_{20} \cdot K_{API}$$

Where:

ρ_{15} = oil density at 20°C, kg/m^3;

ρ_{20} = oil density at 15°C, kg/m^3;

K_{15} = oil density at 20°C to oil density at 15°C conversion factor;

$\rho_{60/60}$ = relative oil density at 60°F (15.556°C);

ρ_{API} = API oil density, °API;

$K_{60/60}$ = oil density at 20°C to relative oil density at 60°F conversion factor 10^3(kg/m^3);

K_{API} = oil density at 20°C to relative oil API density conversion factor, °API/(kg/m^3);

Uncertainties of correction approach are less than 0.01kg/m or 0.01°API, less than 0.01% of oil volume.

Gaseous (natural gas and APG)

Since for the most cases the pressure fixed at the 101.325 kPa (1 atm), the temperature correction can be performed as follows (Equation 4A.1.4).

EQUATION 4A.1.4 (NEW)
CONVERSION OF GAS VOLUME

$$V_{st} = V_g \cdot CF_t$$

Where:

V_{st} = gas volume at the required reference conditions, m^3;

V_g = gas volume at the given reference conditions, m^3;

CF_t =conversion factor, dimensionless.

According to the equation, initial gas volume should be multiplied by the conversion factor to obtain the gas volume at the required temperature. The factors are derived by means of ideal gas equation at the pressure fixed at the level of 101.325 kPa (1 atm). The conversion factors are shown at Table 4A.1.1.

TABLE 4A.1.1 (NEW)
CORRECTION OF GAS VOLUMES TO THE REQUIRED TEMPERATURE CONVERSION FACTORS (CFT)

To / From	15°C
0°C	1.055
20°C	0.983

The difference between ideal and real volumes of APG and natural gas is within 0.55%. This difference can be used to calculate uncertainty of the correction.

Annex 4A.2 Disaggregation of Tier 1 factors presented in Section 4.2.2.3

This Annex presents the percent of emissions that are leaked, vented, and flared in the data sets used for the Tier 1 emission factors. To disaggregate the aggregate Tier 1 EF in the *2019 Refinements* into emissions “leaked,” and “flared,” apply the percent below to the corresponding aggregated value presented in Section 4.2. For an example of this calculation, see Box 4A.2.1 below.

The disaggregation was developed by reviewing the underlying data sets for the emission factors, assigning emission sources to leaked (e.g., emissions leaked from a pipeline), vented (e.g., emissions from venting for liquids unloading), and flared (e.g., emissions from flaring at well completions) emissions, and calculating the percent of total emissions in each category of leak, vent, and flare. Note likely that the fraction of emissions in each category may vary considerably from country to country and over time.

TABLE 4A.2.1 (NEW)
DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR OIL EXPLORATION, 1.B.2.A.I

Category	Sub-category	Emission source	CH_4	CO_2	NMVOC	N_2O	Application
Oil Exploration	Onshore unconventional without flaring or recovery	Leaks	Leaks	0%	0%	0%	Apply percentages to applicable EF (EF based on wells drilled, active oil wells, or onshore oil production)
		Vents	Vents	98%	2%	0%	
		Flares	Flares	2%	98%	100%	
Oil Exploration	Onshore unconventional with flaring or recovery	Leaks	Leaks	0%	0%	0%	Apply percentages to applicable EF (EF based on wells drilled, active oil wells, or onshore oil production)
		Vents	Vents	48%	0%	0%	
		Flares	Flares	52%	100%	100%	
Oil Exploration	Onshore conventional	Leaks	Leaks	0%	0%	0%	Apply percentages to applicable EF (EF based on wells drilled, active oil wells, or onshore oil production)
		Vents	Vents	79%	0%	0%	
		Flares	Flares	21%	100%	100%	

TABLE 4A.2.2 (NEW)
DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR OIL PRODUCTION SEGMENT, 1.B.2.A.II

Category	Sub-category	Emission source	CH_4	CO_2	NMVOC	N_2O	Application
Onshore Production	Most activities occurring with higher- emitting technologies and practices	Leaks	7%	0%	7%	0%	Apply percentages to applicable EF (EF based on either onshore oil production, or active oil well)
		Vents	83%	3%	83%	0%	
		Flares	10%	97%	10%	100%	
Onshore Production	Most activities occurring with lower-emitting technologies and practices	Leaks	9%	0%	9%	0%	Apply percentages to applicable EF (EF based on either onshore oil production, or active oil well)
		Vents	78%	1%	78%	0%	
		Flares	13%	99%	13%	100%	
Oil Sands Mining and Ore Processing	All	Leaks	2%	0%	21%	0%	Apply percentages to applicable EF (EF based on crude bitumen production from surface mining)
		Tailings Ponds	91%	47%	46%	-	
		Exposed Mine Surface	6%	30%	33%	-	
		Vents	0%	3%	-	-	
		Flare	0%	19%	0%	100%	
Oil Sands Upgrading	All	Leaks	8%	0%	39%	0%	Apply percentages to applicable EF (EF based on synthetic crude oil production)
		Vents	82%	82%	53%	-	
		Flare	11%	18%	8%	100%	

TABLE 4A.2.3 (NEW)
DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR OIL REFINING, 1.B.2.A.IV

Category	Sub-category	Emission source	CH_4	CO_2	NMVOC	N_2O	Application
Oil Refining	All	Leaks	99%	45%	98%	1%	Apply percentages to applicable EF (EF based on thousand cubic meters oil refined)
		Flares	1%	55%	2%	99%	

TABLE 4A.2.4 (NEW)
DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR GAS EXPLORATION, 1.B.2.B.I

Category	Sub-category	Emission source	CH_4	CO_2	NMVOC	N_2O	Application
Gas Exploration	Unconventional without flaring or recovery	Leaks	0%	0%	0%	0%	Apply percentages to applicable EF (EF based on wells drilled, active gas wells, or onshore gas production)
		Vents	100%	90%	100%	0%	
		Flares	0%	10%	0%	100%	
Gas Exploration	Onshore unconventional gas exploration with flaring or gas capture	Leaks	0%	0%	0%	0%	Apply percentages to applicable EF (EF based on wells drilled, active gas wells, or onshore gas production)
		Vents	8%	0%	8%	0%	
		Flares	92%	100%	92%	100%	
Gas Exploration	Onshore conventional Gas exploration	Leaks	0%	0%	0%	0%	Apply percentages to applicable EF (EF based on wells drilled, active gas wells, or onshore gas production)
		Vents	99%	0%	99%	0%	
		Flares	1%	100%	1%	100%	

TABLE 4A.2.5 (NEW)
DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR GAS PRODUCTION, 1.B.2.B.II

Category	Sub-category	Emission source	CH_4	CO_2	NMVOC	N_2O	Application
Onshore production	Onshore: Most activities occurring with higher-emitting technologies and practices	Leaks	11%	4%	11%	0%	Apply percentages to applicable EF (EF based on either gas production or gas wells)
		Vents	89%	31%	89%	0%	
		Flare	0%	65%	0%	100%	
Onshore Production	Onshore: Most activities occurring with lower-emitting technologies and practices	Leaks	15%	2%	15%	0%	Apply percentages to applicable EF (EF based on either gas production or gas wells)
		Vents	84%	6%	84%	0%	
		Flare	0%	92%	0%	100%	
Onshore Production – Coal Bed Methane	All	Leaks	53%	0%	53%	0%	Apply percentages to applicable EF (EF based on coal bed methane production)
		Vents	44%	3%	44%	0%	
		Flare	3%	97%	3%	100%	
Offshore Gas production	All	Leaks	23%	0%	23%	0%	Apply percentages to EF (EF based on offshore gas production)
		Vents	77%	1%	77%	0%	
		Flare	0%	99%	0%	100%	

TABLE 4A.2.6 (NEW)
DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR GAS PROCESSING SEGMENT, 1.B.2.B.III

Category	Sub-category	Emission source	CH_4	CO_2	NMVOC	N_2O	Application
Gas Processing	Without LDAR, or with limited LDAR, or 50% of centrifugal compressors are dry seal	Leaks	4%	0%	4%	0%	Apply percentages to applicable EF (EF based on either gas processed or gas produced)
		Vents	91%	1%	91%	1%	
		Flare	5%	99%	5%	99%	
Gas Processing	Extensive LDAR, and around 50% or more of centrifugal compressors are dry seal	Leaks	5%	0%	5%	0%	Apply percentages to applicable EF (EF based on either gas processed or gas produced)
		Vents	95%	1%	95%	0%	
		Flare	0%	99%	0%	100%	
Gas processing	Sour gas (acid gas removal)	Vents	100%	100%	100%	100%	Apply percentages to applicable EF (EF based on either gas processed or gas produced)

TABLE 4A.2.7 (NEW)
DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR GAS TRANSMISSION SEGMENT, 1.B.2.B.IV

Category	Sub-category	Emission source	CH_4	CO_2	NMVOC	N_2O	Application
Gas Transmission	Most activities occurring with higher-emitting technologies and practices	Leaks	67%	27%	67%	NA	Apply percentages to applicable EF (EF based on either gas consumption or kilometre pipeline)
		Vents	33%	12%	33%	NA	
		Flare	0%	61%	0%	NA	
Gas Transmission	Most activities occurring with lower-emitting technologies and practices	Leaks	62%	17%	46%	NA	Apply percentages to applicable EF (EF based on either gas consumption or kilometre pipeline)
		Vents	38%	9%	54%	NA	
		Flare	0%	74%	0%	NA	
Gas Storage	Limited LDAR or most activities occurring with higher-emitting technologies and practices	Leaks	72%	22%	72%	NA	Apply percentages to EF (EF based on gas consumption)
		Vents	28%	7%	28%	NA	
		Flare	0%	71%	0%	NA	
Gas Storage	Extensive LDAR and lower-emitting technologies and practices	Leaks	69%	14%	69%	NA	Apply percentages to EF (EF based on gas consumption)
		Vents	31%	6%	31%	NA	
		Flare	0%	79%	0%	NA	
LNG: Import/ Export	All	Leaks	6%	0%			Apply percentages to EF (EF based on number of stations)
		Vents	91%	0%			
		Flare	3%	100%			

TABLE 4A.2.7 (NEW) (CONTINUED)
DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR GAS TRANSMISSION SEGMENT, 1.B.2.B.IV

Category	Sub-category	Emission source	CH_4	CO_2	NMVOC	N_2O	Application
LNG: Storage	All	Leaks	91%	0%			Apply percentages to EF (EF based on number of stations)
		Vents	0%	0%			
		Flare	9%	100%			

BOX 4A.2.1 (NEW)
EXAMPLE OF CALCULATION OF DISAGGREGATED EMISSION ESTIMATES FOR OIL PRODUCTION

Oil production in Country A occurs entirely onshore. The compiler has assessed available data on technologies and practices and determined that the most appropriate factor is the one for "most activities are occurring with higher-emitting technologies and practices" (i.e., the compiler either does not have information to assess that low-emitting technologies are prevalent, or has assessed that more than 5% of associated gas is vented, or more than 30% of tank throughput is uncontrolled (e.g. without flaring or VRUs)), and that the best available activity data is active onshore oil well counts. In year 2017, country A had 100,000 active onshore oil wells. The table below demonstrates how Country A would use a Tier 1 approach to calculate total emissions for oil production in 2017, and disaggregated emissions for oil production in 2017.

EXAMPLE CALCULATION OF DISAGGREGATED EMISSION ESTIMATE FOR OIL PRODUCTION				
	CH_4	CO_2	NMVOC	N_2O
Calculation of Total Emissions				
EF (tonnes per well) (from Table 4.2.4a)	2.35	8.57	1.01	1.30E-04
Number of wells	100,000	100,000	100,000	100,000
Total tonnes of gas (EF x wells)	235,000	857,000	101,000	13
Disaggregation Percent (from Table 4A.2.2)				
Leaks	7%	0%	7%	0%
Vents	83%	3%	83%	0%
Flares	10%	97%	10%	100%
Disaggregated EF (in Tonnes per well)				
Leaks	0.16	0.00	0.07	0.00
Vents	1.95	0.26	0.84	0.00
Flares	0.24	8.31	0.10	0.00
Disaggregated Emission Estimate, in Tonnes				
Leaks	16,450	-	7,070	-
Vents	195,050	25,710	83,830	-
Flares	23,500	831,290	10,100	13

Annex 4A.3 Definition of terminologies used in Section 4.2

abandoned well: a well no-longer in production or being actively explored; such wells may be unplugged or plugged. Wells plugged according to regulations and abandoned are also known as decommissioned wells. Wells that are not regularly inspected or repaired and remain unplugged are abandoned but not decommissioned.

acid gas: gas that, when mixed with water, forms an acidic solution (e.g. hydrogen sulphide (H_2S) and carbon dioxide (CO_2) - both obtained after sweeting sour gas); see also *sour gas.*

API: the American Petroleum Institute, the primary trade association representing the oil and natural gas industry in the United Status.

API gravity: gravity scale developed by the American Petroleum Institute that expresses the relative density of petroleum liquids as API degrees; most values fall between 10 and 70 degrees API gravity, and the lower the API gravity, the higher the density of a hydrocarbon.

appliance: *see gas appliance.*

asphalt: solid or nearly solid bitumen with impurities (nitrogen, oxygen, sulphur) that can melt upon heating; forms when light components or volatiles of petroleum have been removed or evaporated; see also *bitumen.*

associated petroleum gas (APG): gas produced along with oil.

bitumen: typically solid hydrocarbon with high density (API < 10 degrees; e.g. asphalt); see also *asphalt.*

blow-down: venting for safety precautions during maintenance, or emergency or upset conditions, occurring across segments, and including vented condensate and gas produced simultaneously at the outset of production or when re-starting a well that has been shut down for a period of time, maintenance venting at a processing plant, or pipeline venting

blow out: when well pressure exceeds the wellhead valves' ability to control it and oil and gas are released at the surface; uncontrolled, possibly catastrophic, flow of reservoir fluids into wellbore that may consist of salt water, oil, gas, or a mixture thereof.

bore hole: the hole drilled by the drill bit; the wellbore including open hole or uncased portion of the well.

cap rock: relatively impermeable rock (e.g. shale, anhydrite, salt) that forms a seal above a reservoir rock and prevents fluids from migrating out of the reservoir.

carbon capture and storage (CCS): the process of trapping carbon dioxide (CO_2) and storing it in a way that it is unable to enter the atmosphere.

CO_2 injection: an enhanced oil recovery (EOR) method whereby CO_2 gas is injected into a reservoir to reduce viscosity and increase production.

carbon intensity: average emission rate of carbon dioxide (CO_2) from a source per unit of activity (e.g. g CO_2 per MJ of energy produced).

casing: cement pipe lowered down a borehole meant to prevent fluids from escaping and/or the borehole from collapsing.

casing head: the adapter between the first casing and the wellhead.

category: a subdivision of a sub-sector. For example, a sub-sector of the Energy sector is 1 B Fugitive Emissions from Fuels. Categories under the 1 B sub-sector include 1 B 1 Fugitive emissions from Solid Fuels, 1 B 2 Fugitive emissions from Oil and Natural Gas Systems and 1 B 3 Fugitive emissions from Fuel transformation.

centrifugal compressor: centrifugal compressors are widely used in production, processing, and transmission of natural gas. Seals on the rotating shafts prevent the high-pressure natural gas from escaping the compressor casing. Traditionally, these seals, termed "wet" seals, used high pressure oil as a barrier against escaping gas. An alternative to the traditional wet (oil) seal system is the mechanical dry seal system. This seal system does not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and static pressure. Replacing "wet" (oil) seals with dry seals significantly reduces operating costs and methane emissions (United States Environmental Protection Agency (EPA) 2016b).

chemical flooding: a type of enhanced oil recovery (EOR) that utilizes alkaline or micellar-polymer flooding.

coal bed methane (CBM): natural gas (methane/CH_4, mainly) generated during coal formation and absorbed in coal. Originally extracted as a safety measure to reduce explosion hazards in mines, today CBM is captured and used as a source of energy. For deeper coal formations, hydraulic fracturing may be needed to release the natural gas (https://www.epa.gov/uog/process-unconventional-natural-gas-production).

cold production: non-thermal primary methods of heavy oil production.

completion: process of initiating flow of petroleum or natural gas from a newly drilled well prior to production (a) For *conventional well completion* a reservoir is connected to the wellbore during this process, allowing the flowback of drilling and reservoir fluids (gas, oil, water, mud, etc.) to the surface. While there is flowback, there may be flaring or venting of produced gas from the reservoir. (b) For *unconventional well completions,* if hydraulic fracturing is employed, there may be a higher rate of flowback of water, fracking fluids, reservoir gas and fracturing proppant (e.g. sand) that can release greater amounts of methane and hydrocarbons to the atmosphere when compared to *conventional well completions*. (c) In a *green completion* or *reduced emissions completion* (REC), produced gas following hydraulic fracturing is captured, offsetting the loss of methane and other hydrocarbons during flowback from the well completion.

compressor: a device that raises pressure of air or natural gas so the gas can flow into pipelines or other facilities; see also *centrifugal compressor and reciprocating compressor*.

compressor station or plant: facility with many compressors, auxiliary treatment equipment, and pipeline installations to pump natural gas under pressure over long distances.

condensate: a low-density, high API (50-120 degrees) hydrocarbon associated with natural gas that is in the gas phase under reservoir conditions (temperature, pressure) but becomes liquid when the reservoir, pipeline, or surface facility pressure drops below the dew point. It is mainly composed of propane, butane pentane and heavier hydrocarbon fractions.

conservation efficiency (CE): a factor that expresses the amount of produced gas and vapour captured and used for fuel, produced into gas gathering systems, or re-injected (1.0 = all gas is conserved, utilized or re-injected; 0 = gas is vented or flared).

conventional oil: oil produced from a conventional reservoir

conventional reservoir: a reservoir where buoyant forces maintain hydrocarbons beneath a sealing cap stone and whose properties usually allow oil or natural gas to flow readily into well bores; this is distinct from shale or unconventional reservoirs, where gas may be distributed throughout the reservoir at basin scale and where additional buoyant forces or the influence of a water column is not significant.

crude oil: liquid petroleum as it arises from the ground, distinguished from refined oils that are manufactured from it.

cyclic steam stimulation (CSS): a method of *in situ* oil sand extraction that uses steam to heat the reservoir, allowing bitumen to flow into a vertical or horizontal wellbore; see also *steam-assisted gravity drainage (SAGD).*

decommissioned well: an abandoned well no longer in production that has been isolated according to current regulatory requirements and best practices (e.g. cut-off, sealed, and possibly buried); such wells may still deteriorate over time, and may require inspection and repair when necessary, though the regulatory requirements to do so may vary considerably.

directional drilling: the intentional deviation of a well bore from the path it would have naturally taken by using specialized, steerable drilling equipment; commonly used in shale reservoirs to allow producers to place the borehole in contact with the most productive reservoir rock.

directional well: a well bore that uses special tools and/or techniques to make sure that its path hits a particular target that is usually located away from (as opposed to directly under) the surface location of the well.

distribution: for oil systems, the segment of the system that includes the transport and distribution of refined products, including bulk and retail facilities; for natural gas systems, this segment includes high-pressure gas pipelines that transfer natural gas to the "city gate" and then to end users through underground main and service pipelines, distribution of town gas, and short term surface storage.

dry hole: an exploratory well where no hydrocarbons are found; a non-productive well.

dry gas: natural gas that does not require any hydrocarbon dew-point control to meet sales gas specifications (may require treating to meet water and acid gas (H_2S and CO_2) content); usually produced from shallow (< 1000 m deep) gas wells.

emission control device: a device used to regulate the amount of gasses or air pollutants emitted from a source.

Emissions Trading System (ETS): a greenhouse gas emissions trading scheme in the European Union plus Norway, Iceland, and Liechtenstein.**enhanced coal bed methane (ECBM):** increased methane (CH_4) recovery produced by the injection of CO_2 into coal seams.

enhanced gas recovery (EGR): increased recovery of natural gas by injection of inert gases (e.g. N_2, CO_2) to increase well pressure.

enhanced oil recovery (EOR): recovery of oil from a reservoir by means other than using the natural reservoir pressure; can begin after a secondary recovery process or at any time during the productive life of an oil reservoir; an oil recovery enhancement method that uses sophisticated techniques that restores formation pressure and improves oil displacement or fluid flow in a reservoir; there are three major types: chemical flooding (alkaline flooding or micellar-polymer flooding), miscible displacement (CO_2 injection or hydrocarbon injection) and thermal recovery (steam flood or *in situ* combustion).

exploration: the part of oil and natural gas systems that includes well drilling, stem testing, and well completion; the process of trying to find accumulations of oil and natural gas under the surface of the Earth.

exploration well: a well drilled in an unproven area in an attempt to locate oil and natural gas.

flaring: all burning of waste natural gas and hydrocarbon liquids by flares as a disposal option rather than for the production of useful heat or energy.

flaring destruction efficiency (FE): the fraction of gas that leaves the flare partially or fully burned.

flow-back: gas, crude oil and water (including water injected during hydraulic fracturing) that are produced from a well until the flow of gas and liquid hydrocarbon is steady; occurs after a treatment or in preparation for returning a well to production.

formation carbon dioxide: CO_2 present in the produced oil and gas when it leaves the reservoir.

fuel: any substance burned as a source of energy for heat or electricity.

fuel combustion: the intentional oxidation of materials within an apparatus that is designed to provide heat or mechanical work to a process, or for use away from the apparatus.

fugitive emissions (oil and natural gas): the intentional or unintentional release of greenhouse gases that occur during the extraction, processing and delivery of fossil fuels to the point of final use; this excludes greenhouse gas emissions from fuel combustion. Encompasses venting, flaring, and leaks.

gas appliances: end of pipe equipment such as home heating equipment, water heaters, saunas, stoves, and barbecues that use natural gas.

gathering system: the network of flow lines and process facilities that transport and control the flow of oil or gas from wells to a main storage facility, processing plant, or shipping point (includes pumps, headers, separators, emulsion treaters, tanks, regulators, compressors, dehydrators, valves).

gas injection: the process of pumping associated gas into a reservoir for conservation or to maintain reservoir pressure.

gas-to-oil ratio (GOR): volume of gas at atmospheric pressure produced per unit of oil produced.

gas well: a well with natural gas as the primary product, but can also produce natural gas liquids (e.g. propane and butane) and water.

gross calorific value (GCV): conversion factor to convert a fuel quantity between natural units (e.g. mass or volume) and energy units (energy content), in this case gross energy content (IEA; https://www.iea.org/media/training/alumni/CheatSheet.pdf).

heater treater: a three-phase separator that separates crude oil, water, and associated gas from the output of a well.

heavy crude: a low API (< 20 degrees)/high density hydrocarbon.

horizontal drilling: a subset of directional drilling where the departure of well bore from vertical exceeds ~ 80 degrees.

hydraulic fracturing: a method of enhanced oil or gas recovery in which fluids are pumped into a rock formation at very high pressures in order to fracture the rock and stimulate the flow of natural gas or oil, increasing the volumes that can be recovered. Wells may be drilled vertically hundreds to thousands of feet below the surface and may include horizontal or directional sections extending thousands of feet away from the well.

hydrocarbon: strictly defined as molecules containing only hydrogen and carbon, but the term is used more broadly to include any molecules in petroleum which also contain S, N, or O. Hydrocarbons may exist as a solid, liquid, or gas and are generally used to refer to oil, gas, and natural gas liquids (including condensates).

hydrogen sulphide (H_2S): a poisonous gas present in some subsurface formations.

injection well: a well used to pump water or gas into a reservoir.

***in situ* combustion:** a method of thermal recovery where fire, generated inside a reservoir by injecting oxygen/air, burns heavy hydrocarbons and vaporizes lighter hydrocarbons, pushing out hot combustion gases, steam and oil water while also reducing oil viscosity.

leak: unintentional (i.e., not vented or flared) emissions from equipment components such as valves, connectors, open ended lines, and flanges; can occur in all segments of oil and natural gas systems.

leak detection and repair (LDAR): determination of a leak in a pipeline or piece of equipment using various detection methods followed by repair.

light crude: a high API/low density crude (API > 40 degrees).

light hydrocarbons: low molecular weight hydrocarbons (e.g. methane, ethane, butane)

liquid hydrocarbons: light liquid compounds extracted from gas flow stream (e.g. propane, butane, pentane)

liquids unloading: see unloading

liquefied natural gas (LNG): oilfield or naturally occurring gas (mostly methane and ethane), liquefied at cryogenic temperatures for transportation.

liquid petroleum gas (LPG): a light hydrocarbon that is gaseous at atmospheric temperature and pressure and which is held in a liquid state (by pressure) in order to ease transport and handling; consists of either propane, butane, or mixtures of the two.

lubricants: hydrocarbons produced from distillate or residue that are mainly used to reduce friction between bearing surfaces; includes all finished grades of lubricating oil, from spindle oil to cylinder oil, and those used in greases, including motor oils and all grades of lubricating oil base stocks.

million barrels of oil equivalent (MBOE): a unit of energy based on the energy release by burning one million barrels (one barrel is 42 US gallons or 158.9873 L) of crude oil.

meter and regulator stations: points of transfer where pipeline companies measure gas quality and volumetric flow, and reduce the pressure of pipeline gas to feed natural gas distribution systems.

methane (CH_4): the lightest and most abundant hydrocarbon gas and main component of natural gas.

miscible displacement: a type of enhanced oil recovery (EOR) that uses CO_2 injection or hydrocarbon injection.

natural gas: a gas that occurs naturally and often in association with crude petroleum; a mixture of hydrocarbon gases that is highly compressible and expansible (consists primarily of methane, but also ethane, propane, butane, and pentane; impurities such as CO_2, He, N, and H_2S may also be present).

natural gas liquids (NGLs): liquid natural gas components including condensate (low vapor pressure NGL), natural gasoline (intermediate vapor pressure NGL), and liquified petroleum gas (high vapor pressure NGL). NGLs include: propane, butane, pentane, hexane, heptane but NOT methane and ethane.

net calorific value (NCV): conversion factor to convert a fuel quantity between natural units (e.g. mass or volume) and energy units (energy content), in this case net energy content (IEA; https://www.iea.org/media/training/alumni/CheatSheet.pdf

non-methane volatile organic compounds (NMVOC): a class of emissions which includes a wide range of specific organic chemical substances which are precursors for the formation of ozone, a greenhouse gas and air pollutant in the troposphere (lower atmosphere).

off-gas: the exhaust gas from a chemical process (combustion or non-combustion). The off gas may be vented to the atmosphere, burned for energy recovery or flared (without energy recovery), or used as a feedstock for another chemical process.

oil: a mixture of liquid hydrocarbons of different molecular weights.

oil sand: are a type of unconventional petroleum deposit made of up a mixture of sand, clay, and water, saturated with a highly viscous form of petroleum called crude bitumen. In the context of Canadian oil sands, the API is < 10 degrees, and *in situ* recovery and mining methods are used to extract the resource.

oil shale: a sedimentary rock containing organic matter in the form of kerogen, a waxy hydrocarbon-rich material regarded as a precursor to petroleum. Oil shale may be burned directly or processed by, for example, heating to extract shale oil (United Nations Department of Economic and Social Affairs Statistics Division 2018).

oil well: a producing well that has oil as its primary product; such a well always produces some associated gas and frequently water as well.

permeability: the property of a geologic formation that quantifies the flow of fluid through pore spaces and into the well bore.

petroleum: a generic term for hydrocarbons that includes crude oil, natural gas liquids, natural gas, and their products; a complex mixture of naturally occurring hydrocarbon compounds found in rock which range from solid to gas, but usually refers to liquid crude oil. Impurities such as sulphur, oxygen and nitrogen are common and there is considerable variation in colour, gravity, odour, sulphur content and viscosity in petroleum from different areas.

pipeline: a tube or system of tubes used to transport crude oil and natural gas from the field or gathering system to the refinery.

pipeline capacity: the volume of gas or oil needed to maintain a full pipeline expressed in barrels per foot (bbl/ft).

pipeline gas: gas that is sufficiently dry that it will not precipitate out natural gas liquids (NGLs) at pressure and that has enough pressure to enter high-pressure gas pipelines.

pipeline oil: oil whose water, sediment and emulsion content is low enough for pipeline shipment.

plug and abandon: to prepare a well bore to be closed permanently (shut in and permanently isolated) for various reasons (e.g. after it is determined that there are insufficient hydrocarbons to complete an exploratory well, after production operations have drained a reservoir, geological reasons, regulatory reasons). Regulatory requirements usually dictate how this occurs (most require cement plugs to be placed in the well born with inflow or integrity tests made at each stage to confirm hydraulic isolation).

pore gas: interstitial gas stored in the pore space of reservoir rock.

porosity: the percent of void in a porous rock compared to solid.

pneumatic devices: chemical injection pumps, starter motors on compressor engines, instrument control loops, liquid level controllers, pressure regulators, and valve controllers that use pressurized natural gas or compressed air as the supply medium.

primary fuels: fuels extracted directly from natural resources; examples include crude oil, natural gas, coals, etc.

processing: the segment of natural gas systems where natural gas liquids (NGLs) and other constituents (e.g. sulphur) from raw gas are removed to prepare "pipeline quality" gas.

production: the segment of Oil Systems that includes the process of recovering oil from the wellhead or at the oil sands/oil shale mine to delivery at the start of the oil transmission system; also included in this segment are any on-site upgrading activities. For Natural Gas systems this segment includes recovering gas from the wellhead and delivery of that gas to either the inlet of a gas processing facility or a tie-in point of a gas transmission system; also included in this section is gathering and boosting stations.

reciprocating compressor: a compressor that uses pistons driven by a crankshaft to deliver gases at high pressure.

refining: the segment of Oil Systems where refineries process crude oils, natural gas liquids (NGLs) and synthetic crude oils into final products (e.g. primary fuels and lubricants).

reservoir: an underground formation where oil and gas has accumulated; consists of porous rock that holds oil and gas and a cap rock that prevents its escape.

secondary recovery: the recovery of oil or gas by artificially maintaining or enhancing reservoir pressure by injection gas, water or other substances into the reservoir rock.

sector: greenhouse gas emission and removal estimates are divided into main sectors (Energy, Industrial Process and Product Use (IPPU), Agriculture Forestry and Other Land Use (AFOLU), Waste and Other), which are groupings of related processes, sources and sinks.

segment: a sub-division of the Fugitive Emissions from Oil Systems (1 B 2 a) and Fugitive Emissions from Natural Gas Systems (1 B 2 b) sub-categories that refers to the type of activity within the system. For example, 1 B 2 b iii 1 Exploration and 1 B 2 b iii 2 Production are segments of 1 B 2 b.

shale: a fine grained impervious sedimentary rock of clays and other minerals (including high percentage of quartz).

shale gas: natural gas produced from low-permeability deep shale formations; shale that is thermally mature enough and has sufficient natural gas content to produce economic quantities of natural gas.

shale oil: an unconventional oil produced from oil shale rock fragments by pyrolysis, hydrogenation, or thermal dissolution.

shut in well: a well capable of producing but is not currently due to numerous reasons.

sour: oil or gas contaminated with sulphur or sulphur compounds (especially hydrogen sulphide).

sour gas: natural gas that must be treated to satisfy sales gas restrictions on H2S content; see also *sweet gas*.

sour crude: crude oil with high sulphur content.

standard temperature and pressure (STP): 15 degrees Celsius and 101.325 kPa (1 atm) atmospheric pressure.

steam assisted gravity drainage (SAGD): a method of *in situ* oil sand extraction that uses steam to heat the reservoir, allowing bitumen to flow into a vertical or horizontal wellbore; see also *cyclic steam stimulation (CSS).*

storage: natural gas kept temporarily on long-term in above ground tanks or below-ground formations. Crude oils or refined products stored in above ground tanks.

sub-category: a division of a category. For example, subcategories of 1 B 2 (Fugitive Emissions from Oil and Natural Gas Systems) include 1 B 2 a Fugitive Emissions from Oil Systems and 1 B 2 b Fugitive Emissions from Natural Gas Systems. Subcategories can be further divided into *segments.*

sub-sector: a division of a sector. For the Energy sector, sub-sectors include 1 A Fuel Combustion Activities and 1 B Fugitive Emissions from Fuels, for example.

sub-segment: a division of a segment of Oil or Natural Gas Systems by technology or practice.

sweet: lacking appreciable amounts of sulphur or sulphur compounds.

sweet crude oil: oil with small amounts of H_2S and/or CO_2.

sweet gas: natural gas that does not contain any appreciable amount of H_2S (i.e. does not require treatment to meet requirements for H_2S content).

sweetening: the process that removes hydrogen sulphide or carbon dioxide from a gas stream.

synthetic crude oil (SCO): output from a bitumen or extra heavy oil upgrader, usually in connection with oil sand production or output from oil shale pyrolysis.

synthetic natural gas (SNG): gas obtained from heating coal or refining heavy hydrocarbons.

tar sand: a sand body containing heavy hydrocarbon residues (e.g. tar or asphalt) or degraded oil that has lost its volatile components; hydrocarbons can be liberated by heating and other processes at typically high cost. Also known as oil sands.

thermal recovery: a type of enhanced oil recovery (EOR) that uses stream flood or *in situ* combustion; a process that introduces heat into a reservoir to produce viscous, thick oils (i.e. API < 20 degrees; oils that cannot flow unless heated to reduce viscosity and allow flow toward producing well); encompasses hot fluid injection (steam injection, stream flood or cyclic steam injection), hot water flooding, and *in situ* combustion processes

tight gas: gas produced from a relatively impermeable reservoir rock that is generally difficult to produce without stimulation operations; generally used for reservoirs other than shale that fit this description.

town gas: a manufactured gaseous fuel produced for sale to commercial and residential consumers. Coal gas contains hydrogen (around 50%), carbon monoxide (around 10%), methane (around 35%) and volatile hydrocarbons (around 5%) together with carbon dioxide and nitrogen (each less than 1%); also called coal gas.

transmission: gas transported in high pressure, large diameter pipelines from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants.
transmission compressor station: stations placed within natural gas transmission systems to help maintain the pressure of the gas within a pipeline as it flows from the natural gas field to market.

transport: the segment of Oil Systems that is related to the transport of marketable crude (conventional, heavy, and synthetic crude oil and bitumen) to upgraders and refineries by pipeline, marine tankers, tank trucks, and rail cars.

unconventional resource or reservoir: a term for oil and natural gas that is produced by means that do not meet the criteria for conventional production; presently, used in reference to oil and gas resources whose porosity, permeability fluid trapping mechanism, or other characteristics differ from conventional sandstone and carbonate reservoirs (examples include coal bed methane, gas hydrates, shale gas, fractured reservoirs, tight gas, oil sands).

underground gas storage: storage of gas in salt domes, salt layers, or depleted oil and gas fields.

unload: to restore gas production by removing liquids (including oil, condensate, and water) that have accumulated in a gas well. Liquids can be removed without venting (e.g. with pumps or modified well tubing) or with venting, such as by diverting the flow from the well to an atmospheric vent.

upgrader: a refinery unit that improves or upgrades heavy oil to produce higher-quality hydrocarbon liquids or upgraded synthetic crude.

venting: emissions from venting of associated gas and waste gas/vapour streams and oil and natural gas facilities; this includes all engineered or intentional discharges of waste gas streams and process by-products to the atmosphere, including emergency discharges, and the release may be continuous or intermittent.

vapour recovery unit (VRU): a system used to recover vapours formed inside sealed crude oil or condensate tanks; consists of a switch that detects pressure variations within a tank and turns a compressor on and off. The compressor sucks vapours through a scrubber that catches liquids and vapours for return to tanks or pipelines.

water flooding: a secondary oil recovery method where water is injected into a reservoir formation to displace residual oil into adjacent production wells.

well blow-out: *see blowout.*

well bore: a drilled hole or borehole, including the open hole or uncased portion of the well.

well completion: see *completion.*

well head: the system of spools, valves and assorted adapters that provide pressure control of a production well.

well integrity: the zonal isolation of liquids and gases.

well servicing: maintenance procedures performed on oil and gas wells after the have been completed and production has begun; these procedures maintain or enhance well productivity.

well testing: a series of activities and tests designed to understand and characterize the characteristics of underground reservoirs where hydrocarbons are trapped.

wet gas: natural gas containing significant heavier hydrocarbons (propane, butane and other NGLs) and that is < 85% methane.

wet oil: oil containing basic sediment and water.

workover: repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons.

Appendix 4a.1 Fugitive emissions from mining, processing, storage and transportation of coal: Basis for Future Methodological Development

Based on the current state of research and data availability, a methodology for estimating emissions from abandoned surface mining has not yet been able to be developed. However, general methodological issues are mentioned below for countries to consider as a basis for future methodological development.

Appendix 4a.1.1 Abandoned Surface Mines

Closed, or abandoned, surface coal mines may continue to be a source of greenhouse gas emissions for some time after the mines have been closed or decommissioned. For the purpose of the emissions inventory compilation, a first critical step is to ensure that each mine is classified in one and only one inventory database (e.g., active or abandoned).

It is also important to consider sub-sector allocation issues - to separate any emissions from abandoned surface mines from those of uncontrolled combustion and burning of coal deposits, to avoid double counting. CO_2 emissions can arise from both low-temperature oxidation of exposed coal-bearing rocks and uncontrolled combustion. The CO_2 emissions from uncontrolled combustion should be reported under *1.B.1.b Uncontrolled Combustion, and Burning Coal Dumps*.

Countries considering activity data for estimating emissions from abandoned surface mines may take into account factors such as the surface area of exposure coal, the degree of flooding and the extent and type of mine rehabilitation that has taken place.

For CO_2 and CH_4 emission factors, consideration may be given to the type of coal mined, eg bituminous, subbituminous, lignite etc., mine site management practices and how the emission factors are likely to change over time since mine closure.

In general, more work needs to take place in order to build a basis for robust and representative Tier 1 methodology development. This is particularly the case for developing appropriate emission factors, as well as understanding the variability and uncertainty associated with emissions from this source.

Appendix 4a.2 Fugitive Greenhouse Gas Emissions from Wood Pellet production: Basis for Future Methodological Development

Fugitive emissions are likely from the wood pellet production. The quantities of emissions will be variable, and uncertain. At the time the *2019 Refinement* was created, there was insufficient information available in the scientific literature to select emission factors suitable for estimating emissions and therefore a methodology is not provided. If countries have developed country specific methods for estimating emissions from biomass transformation process, they may estimate and report emissions. This appendix provides a basis for future methodological development to estimate fugitive greenhouse gas emissions from wood pellet production.

BACKGROUND

Biomass is the fourth largest source of energy worldwide and provides basic energy requirements for cooking and heating of rural households in developing countries. Biomass densification has aroused a great deal of interest in recent years as a technique to enhance the use of residues as energy source. The densified biomass produced is mostly in the form of briquettes in developing countries and in the form of pellets in developed countries.

Wood Pellets

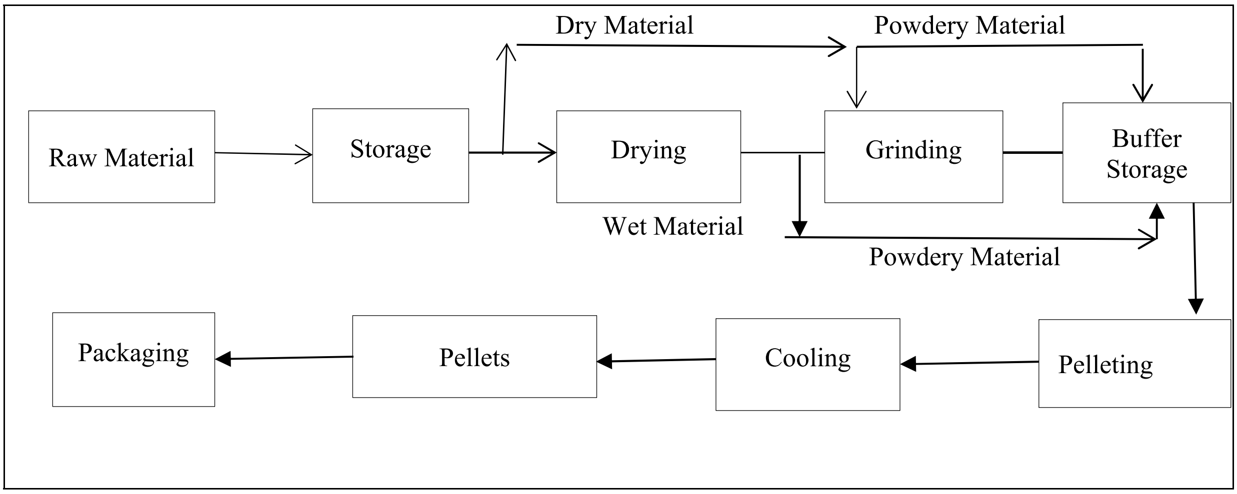
Wood pellets are a type of wood fuel, usually produced as a by-product of sawmilling and other wood transformation activities. Wood pellets are normally produced by compressing dry wood materials to a desired size. First, raw wood materials are passed through a hammer mill and dryer to achieve consistent moisture content. Then, the dry wood particles are fed to a press. In the press they are squeezed through a die having holes of the required size. The high pressure causes the temperature of the wood to increase greatly, causing the lignin to plasticize slightly and form a natural ‘glue’ that holds the pellet together. The pellets are usually 6 to 8 mm in diameter and 2 cm in length.

According to Global Bionergy Statistics 2017 (WBA, 2018), 28 million tonnes of pellets are produced annually. Pellets are thus contributing substantially to global bioenergy trade. Pelleting technology is also considered as a mature technology. From environmental context, it is well documented that all biomass gradually decomposes over time, both chemically and biologically, slowly releasing toxic and oxygen-depleting gases such as CO, CO_2 and CH_4 (Kuang et al, 2008). Limited studies (Svedberg et al., 2004) have reported the composition of the off-gas emissions from stored wood pellets. However, CO, CO_2, CH_4 and non-methane organic compounds are commonly identified in the off-gases from biomass (Johansson et al., 2004). At the pellet production plant, emission of fugitive methane (CH_4) gas may occur at the various stages of production. These include: Pre-processing where the raw material is chipped into small bits; Pelleting; Pellet drying; Pellet storage and pellet drying (Figure 4a.2.2). The delivery, storage and processing of raw materials for pellet production and subsequent handling of the pellets within the pelleting plant enhances the fugitive emissions over and above the emissions associated with natural decay.

Specifically, emissions to air may occur during the wood pellet manufacturing process from sources such as dryers, coolers, pelletizers, hammer mills, and conveyors. Fugitive emissions are also released during the handling, storage and transportation of the materials. Fugitive emissions are unintentional or incidental releases. The significance of fugitive emissions at wood pellet manufacturing facilities may vary depending on the type of raw material, method of transportation and specific process used in the production of the wood pellets. Major sources of these emissions include raw material handling, raw material storage piles, conveyor transfer points, yard dust, haul road dust and engine exhaust (British Columbia, Ministry of Environment, 2011).

The process of wood pellet production follows various distinct stages which include: receipt of the raw material, storage, drying, grinding pelleting, cooling and packaging as illustrated in Figure 4a.2.1.

Figure 4a.2.1 (New) Flow diagram of wood pellet production process

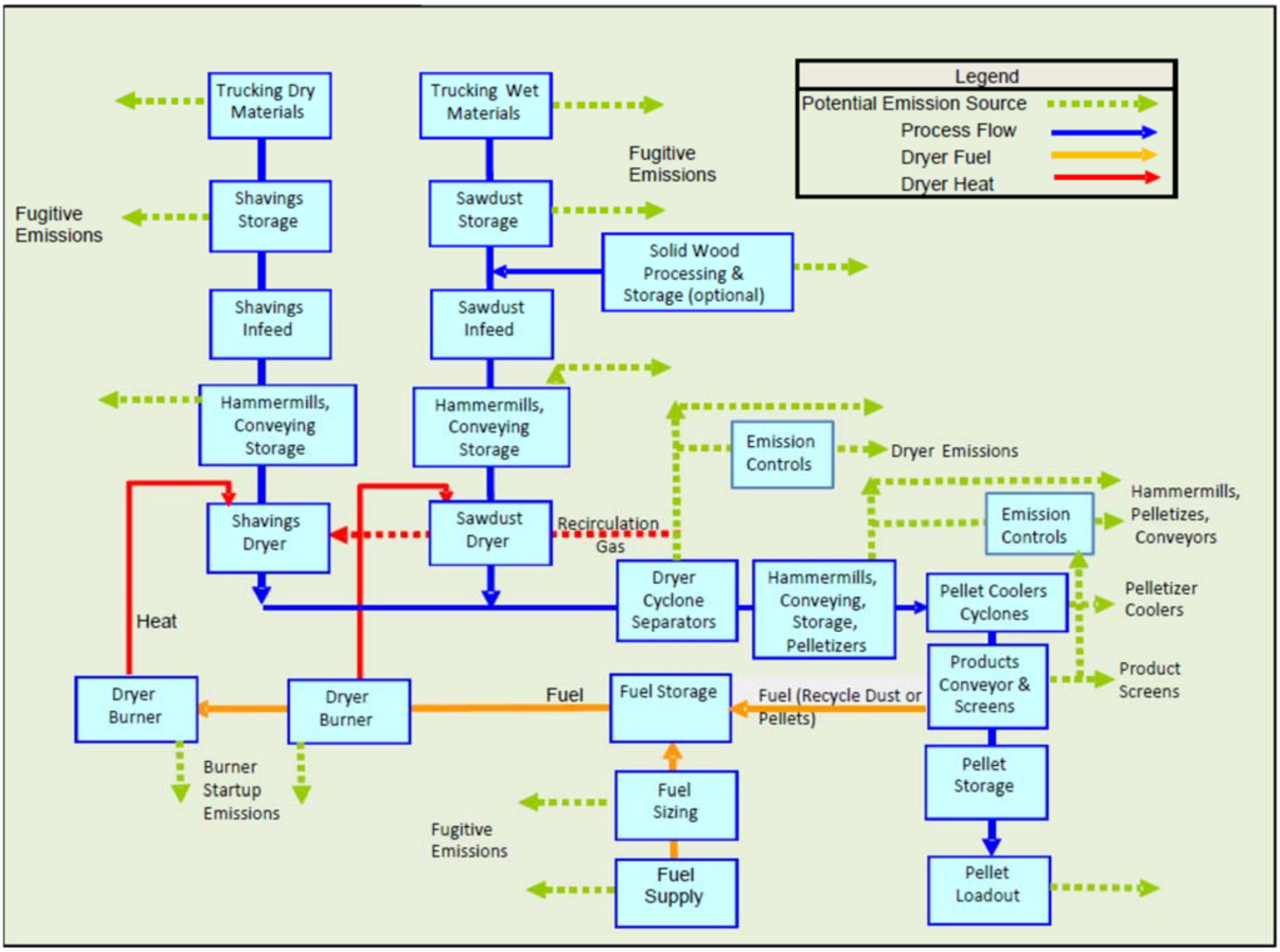


Note: Source: Adapted from Grover and Mishra, 1996, Olsson, 2002

Fugitive Emissions from Pellet Production

The fugitive emissions arising during the pellet manufacture would be classified under category 1B1c of the *2006 IPCC Guidelines*, as they are part of emissions from biomass fuel transformations. The possible sources of fugitive emissions from pellet production are indicated in Figure 4a.2.2. Inventory compilers need consider including only emissions arising within the pellet mill, namely from the receipt of the raw materials to the storage of pellets prior to transportation to end user.

Figure 4a.2.2 (New) Emissions Diagram for a Typical Pellet Plant (Two Dryers)



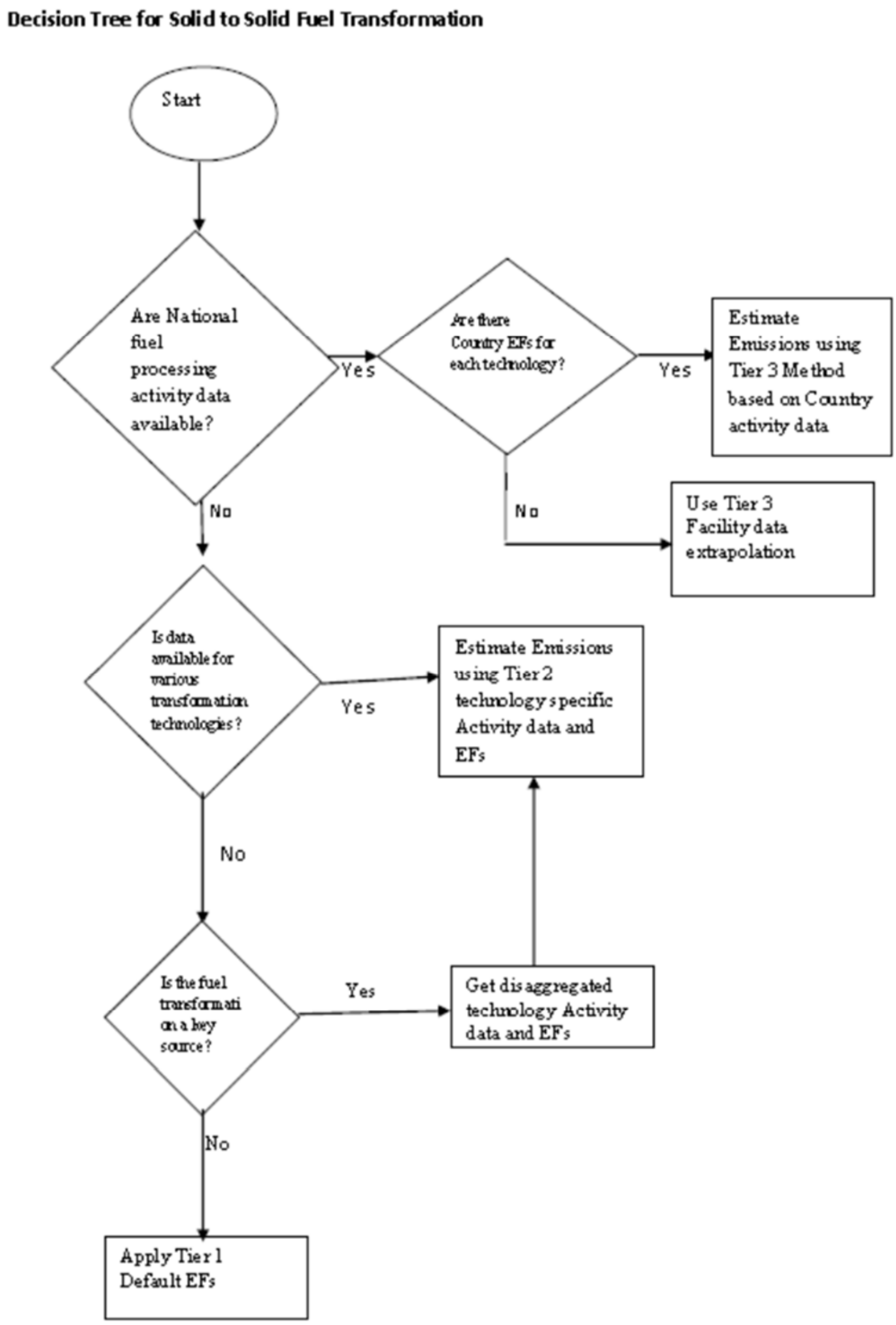
Source: British Columbia, Ministry of Energy, 2011

METHODOLOGICAL ISSUES

The CO_2 fugitive emissions from the biomass and the biomass part of MSW are biogenic emissions and should be estimated for inclusion as an information item in the Energy Sector, as those feedstocks are combusted for energy purposes. For more information on reporting of biomass emissions, please see Section 4.2.2.3 of Volume 2, Chapter 1.

The choice of the method for estimating the fugitive emission depends on the nature and level of disaggregation of activity data and emission factors available in the country. Where there is no country or technology specific data, a Tier 1 method could be developed to estimate emissions using default emission factors. In the case where country specific emission factors are available but the activity data are not disaggregated by each transformation technology, a Tier 2 method could be developed. Finally, where technology specific data and emission factors are available, a Tier 3 method could be used. A proposed decision tree for estimating emissions from solid biomass fuel transformation is given in Figure 4a.2.3.

3834 **Figure 4a.2.3 (New) Proposed decision tree for estimating fugitive emissions from wood pellet**
3835 **production**



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CHOICE OF EMISSION FACTOR

The fugitive emissions from the pellet manufacture are confined to the milling plant but exclude the process energy used for the compaction process. The available literature reviewed at the time of writing (Sjølie and Birger, 2011; Agar et al, 2015; Murphy et al, 2015, Magelli et al, 2009; and Wang et al, 2017) provided emission factors for pellet production largely based on lifecycle analysis. No emission factors suitable for use in national GHG inventories were found to allow the estimation of the fugitive emissions arising at pellet production operations.

Choice of activity data

The activity data required to enable for the estimation of fugitive emissions arising during the manufacture of pellets from solid biomass materials. These include the:

- Quantity of solid biomass input materials including biomass waste and cut wood, available for pelleting;
- Quantity of the pellet and duration of storage prior to being transported to final end-use points.

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Appendix 4a.3 Fugitive Emissions from Biomass to Liquid and Biomass to Gas: Basis for Future Methodological Development

This Appendix provides a basis for future methodological development rather than complete guidance.

Biomass to gaseous (BtG) and biomass to liquid (BtL) gasification transformation processes are processes that use as feedstock woody biomass, agricultural and forest residues and waste biomass (sorted municipal and commercial waste), for example. Therefore, these feedstocks used in these processes does not have carbon of fossil origin, except from Municipal Solid Waste (MSW) that might include some carbon of fossil origin. The CO_2 fugitive emissions from the biomass and the biomass part of MSW are biogenic emissions and should be estimated for inclusion as an information item in the Energy Sector, as those feedstocks are combusted for energy purposes. For more information on reporting of biomass emissions, please see Section 4.2.2.3 of Volume 2, Chapter 1.

Currently, most BtG and BtL plants are either on demonstration or pilot scales and, hence, there is minimal literature describing research into the emissions from these processes (Van der Drift, A; Boerrigter, H, 2006; OCDE/IEA, 2007; AIL, S.S.; DASAPPA, S., 2016; NETL/DOE, 2016).

METHODOLOGICAL ISSUES

The choice of method will depend on the technologies that are operational in countries, including whether the technologies analysed in this section are *key categories* in the country, and to what extent country and plant-specific information is available or can be gathered.

The most accurate fugitive emission estimates can be developed by determining the emissions on a plant-by-plant basis and/or differentiated for each feedstock category (e.g., wood biomass, agricultural and forest residues and MSW). The methods for estimating CO_2, CH_4 and N_2O fugitive emissions from these technologies vary because of the different factors that influence emission levels.

The general approach to calculate greenhouse gas emissions from those technologies is to obtain the amount of feedstock used and to investigate the related greenhouse gas emission factors, preferably from country-specific information on the carbon content.

To estimate fugitive CO_2 emissions, it will be necessary to:

- Identify types of biomass used as feedstock (wood, agriculture and forest residue or waste biomass (sorted municipal and/or commercial waste));
- Compile data on the amount of feedstock used (e.g. amount of biomass or amount of syngas produced, when MSW is the feedstock used in BtL or BtG plants).

CHOICE OF METHODS, DECISION TREES, TIERS

There is limited information about gasification transformation technologies. From the information available, it was considered that fugitive emissions are most likely to occur at the gasification stage. The fugitive emissions resulting from the syngas transformation at the Fischer and Tropsch stage were considered negligible, as it is an energy related processes.

The method for estimating fugitive emissions from BtL and BtG technologies is based on an estimate of the carbon content in the feedstock combusted and converting the product to greenhouse gas emissions.

As BtG and BtL are still emerging technologies, and there are currently very few large scale plants worldwide and methodologies to calculate Tier 2 and Tier 3 are not provided. Inventory compilers could choose to use higher Tier methods to estimate emissions, but they need to transparently document the approaches used and state how their methods accurately and completely estimate emissions.

The activity data required is the amount of biomass inputs into BtL or BtG processes in terajoules (TJ) and the syngas produced, when MSW is the feedstock input, and the emission factors are based on the carbon content of the feedstock.

The choice of method depends on the country specific information available, and is given in the decision tree in Figure 4.3.5, in the Subsection 4.3.2.1.1 Gasification Transformation Processes.

TIER 1

The Tier 1 method is a simple method that can be used when fugitive emissions from BtG and BtL technologies are not significant.

When biomass is the feedstock used in BtL and BtG plants, fugitive emissions of CO_2, CH_4 can be estimated from the amount of biomass (such as wood and agriculture and forest residues) used in BtL and BtG plants and the related emission factors. Fugitive Emissions of N_2O at BtL or BtG gasification facilities can be considered negligible.

If Municipal Solid Waste (MSW) is the feedstock used in BtL or BtG plants, fugitive emissions of CO_2, CH_4 and N_2O can be estimated from the amount of syngas produced and the emission factor for fugitive emissions.

The application of a Tier1 approach is done using Equation 4a.3.1 presented below.

EQUATION 4A.3.1 (NEW)
FUGITIVE GHG EMISSIONS FROM GASIFICATION PROCESSES

$$E_{gas\ i} = (FSj \bullet EFi) \bullet 10^{-6}$$

Where:

$E_{gas\ i}$ = Emissions of gas i (CO_2, CH_4 and N_2O) in inventory year (Gg/yr) emitted at gasification station of BtL or BtG facilities

FSj = total amount of biomass or syngas produced (TJ)

EFi = gas i emission factor, kg gas i/TJ of biomass or syngas

10^{-6} = conversion factor from kilogram to gigagram

CHOICE OF EMISSION FACTOR

Biomass

The emission factors for gasification process of BtG and BtL are provided based on the carbon contents of biomass used in a selection of plants and the composition of its syngas, as analysed by Asadullah (2014), and considering 1% of fugitive emissions are release in the gasification stage (Table 4a.3.1). It was also considered that all the biomass is burned, and that there is no char formation. Asadullah (2014) provides information on gas composition (H_2, CO, CH_4, CO_2, N_2) by volume % of 15 biomass gasification plants that use as feedstocks wood chip, eucalyptus wood, sawdust, sunflower seed pellet, corncob, olive kernel, wood, rice husk, poplar chips, and seed corn.

TABLE 4A.3.1
EMISSION FACTORS FOR GASIFICATION PROCESSES OF BTG AND BTL

	EF CO_2 (kg CO_2/TJ[a])	EF CH_4 (kg CH_4/TJ[a])	EF N_2O (kg N_2O/TJ[a])
Biomass	125	18.3	n.d.

[a] Converted from kg CO_2/ton C and kg CH_4/ton C to kg CO_2/TJ and kg CH_4/TJ, respectively, based on the carbon content values of biomass in Table 1.3 of Chapter 1 Introduction of Volume 2 Energy

n.d. – Not Determined

Source: estimated based on Asadullah (2014)

Municipal Solid Waste

There is no available information to estimate emission factor for fugitive emissions from BtG and BtL facilities related to MSW feedstock.

CHOICE OF ACTIVITY DATA

The activity data required for Tier 1 and Tier 2 are the amount of biomass gasified at gasification stage in terajoules (TJ) or the amount of syngas produced in terajoules (TJ), when MSW is the feedstock used in BtG and BtL plants. Countries that use these technologies should have plant-specific data on the amount of biomass gasified or the syngas produced.

UNCERTAINTY ASSESSMENT

Biomass to gaseous and biomass to liquid technologies

Estimates of fugitive emissions from BtG and BtL facilities are likely to be highly uncertain due to lack of information about fugitive emissions from these technologies. More research and development is needed on these technologies, especially direct measurement on all stages to confirm which ones present fugitive emissions.

Emission factor uncertainties

There is minimal information in the literature from which to derive emission factors, and there are currently few large scale BtG and BtL facilities. The fugitive emission factors provided in these guidelines were estimated based on very few data and uncertainties are large.

Activity data uncertainties

Where activity data are obtained from plants, uncertainty estimates could be obtained from the plant operators.

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